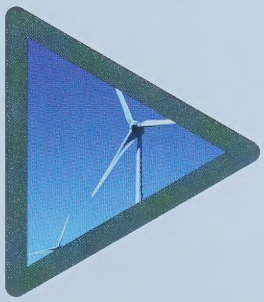
WHAT'S NEXT.

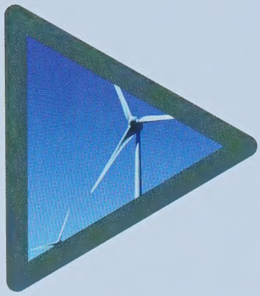



AltaGas

Well connected.

ALTAGAS INCOME TRUST

2007 ANNUAL REPORT

Growth

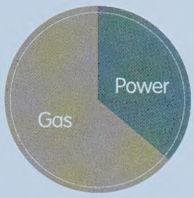
Sustainable, balanced growth of our energy infrastructure business.

Our goal is to build long-term, sustainable value for our investors. To achieve this, we focus on disciplined and balanced growth in energy infrastructure assets and services, including renewable energy.

1996

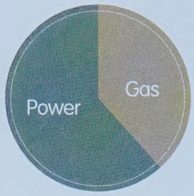
$2.9 million
operating income predominantly from natural gas gathering and processing and gas services.

2002



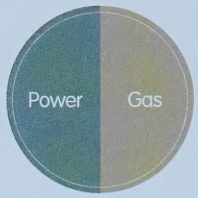
$61.0 million
operating income from natural gas gathering and processing, extraction and transmission, natural gas distribution, energy services and AltaGas' first investment in power generation.

2007



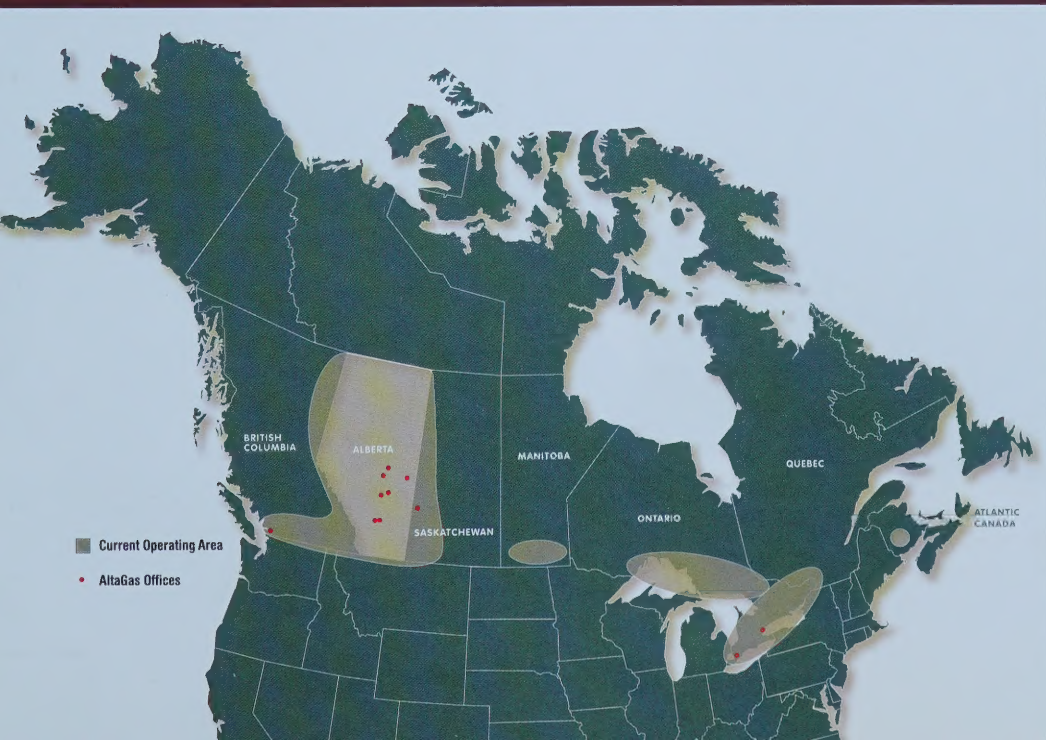
$126.6 million
operating income from AltaGas' gas and power businesses. The gas business includes extraction and transmission, natural gas gathering and processing and energy services. The power business includes coal-fired and gas-fired generation as well as current development plans to spend approximately $400 million on 175 MW of renewable energy initiatives.

FUTURE



AltaGas' business is balanced between natural gas and power infrastructure to ensure strong, sustainable results.

Current Areas of Operation



Contents

Strength

Financial Highlights

($ millions except as indicated)	**2007**	2006	2005	2004	2003
Revenue	**1,428.4**	1,362.6	1,502.3	864.6	710.6
Net revenue [1]	**324.0**	318.9	296.9	250.4	217.3
EBITDA [1]	**173.7**	173.1	155.5	133.4	121.9
Net income	**108.8**	114.5	90.3	65.8	38.3
Net income before tax [1]	**114.7**	113.4	89.0	70.4	61.5
Total assets	**1,199.8**	1,109.6	1,068.3	1,108.6	919.3
Total debt	**220.7**	265.5	269.0	359.5	396.9
Debt as a percent of total capitalization (%)	**27.4**	33.4	36.0	42.6	52.2
Funds from operations [1]	**162.9**	161.7	129.0	108.6	90.2
Dividends/distributions declared [2]	**118.6**	110.8	100.0	66.7	17.3
$ per basic unit					
EBITDA [1]	**3.03**	3.12	2.88	2.70	2.68
Net income	**1.90**	2.06	1.67	1.33	0.84
Net income before tax [1]	**2.00**	2.04	1.65	1.43	1.35
Funds from operations [1]	**2.84**	2.91	2.39	2.20	1.98
Dividends/distributions declared per unit [2]	**2.065**	1.995	1.85	1.31	0.38

(1) Non-GAAP financial measures. See discussion beginning on page 28 in the Management's Discussion and Analysis.

(2) In 2007 distributed an additional $4.2 million ($0.076 per unit) in the form of AltaGas Utility Group Inc. shares. In 2005 distributed an additional $29.3 million ($0.54 per unit) in the form of AltaGas Utility Group Inc. shares.

We have the financial discipline, strength and flexibility to pursue growth opportunities, while continuing to deliver earnings growth, strong returns on equity and stable distributions.

Regardless of its corporate structure, AltaGas has always focused on traditional financial metrics to deliver strong returns to investors.

Net Income
$ millions

Over the past five years, net income has almost tripled from $38.3 million to $108.8 million.

* In 2007 net income included a negative non-cash tax adjustment of $5.4 million due to SIFT tax. See discussion beginning on page 24 in Management's Discussion and Analysis.
** Figure calculated with adjustment due to SIFT tax.

Funds from Operations
$ millions

Cumulative average growth of 16 percent in funds from operations from 2003 to 2007.

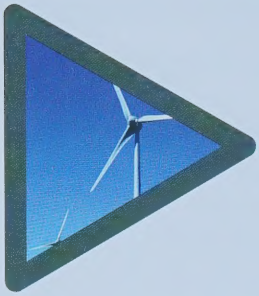
Cash Dividends/Distributions Declared per Unit
$

Distributions have increased over the past five years while remaining within conservative payout ratios.

Return on Equity
%

Return on equity has increased almost 9 percentage points over the past five years, from 10.9 percent to 19.8 percent.

* In 2007 return on equity was negatively impacted by the non-cash tax adjustment due to SIFT tax.
** Figure calculated with adjustment due to SIFT tax.

Strategy

Our strategy is working. AltaGas is growing its energy infrastructure business. Our growth will be balanced between our gas and power businesses, diversified geographically and by fuel source. We focus on assets that are complementary to our existing businesses: low-risk, long-life and profitable, including renewable energy sources. We grow where it makes sense – where the assets contribute long-term, sustainable value to our investors.

strategies

Discipline

Focus on disciplined financial strategy and targets to maintain balance sheet strength and financial flexibility to support future growth.

Balance

Balance growth in gas and power over time to mitigate risks, while maintaining the appropriate risk-return balance. Increase value and profitability of existing assets.

Diversification

Seek new opportunities to complement current assets and diversify geographically, by contract type and fuel source – pursuing gas, coal and renewable energy opportunities.

2007 progress

Distributions increased, while remaining within a conservative payout ratio.

Operating income and return on equity continued to be strong.

DBRS and S&P recently affirmed our investment-grade credit ratings.

With the acquisition of Taylor NGL Limited Partnership, remain within our target debt-to-capitalization range.

Initiated the acquisition of Taylor NGL Limited Partnership, adding low-risk, long-life complementary assets, further balancing AltaGas.

Gas business: entered gas storage in Ontario; added two coal bed methane (CBM) processing facilities and a gathering pipeline; completed Cold Lake Orion project; optimized existing field gathering and processing facilities; and divested non-core oil and gas production assets.

Power business: acquired additional gas-fired peaking capacity; began construction of Bear Mountain Wind Park in B.C.; and acquired interest in run-of-river hydroelectric generation and projects in B.C.

Executed our strategy of adding assets in different geographic locations with complementary contractual terms and diversifying our power business by fuel type.

Added incremental gas-fired peaking capacity. Began construction of Bear Mountain Wind Park in B.C.

Acquired run-of-river hydro interest and development projects in B.C. through the acquisition of Taylor NGL Limited Partnership.

Made our first move into natural gas storage, acquiring an interest in a storage project in Sarnia, ON.

what's NEXT

Regardless of our corporate structure, continue to focus on traditional financial metrics – earnings and return on equity – as well as maintain a strong balance sheet and investment-grade credit ratings. Maintain our conservative payout ratios and grow earnings faster than distributions.

Our financial discipline and effective risk management strategies provide us with the flexibility to grow our business, while ensuring stability and growing returns for our investors.

Balance growth in gas and power infrastructure to ensure a strong, sustainable business. Continue to optimize existing infrastructure and services.

Current growth plans include investment in both gas and power projects. The magnitude of the investment in gas and power assets will vary from year to year. Over time growth will be balanced across both businesses.

Diversify AltaGas' asset base geographically and by fuel source with stable, low-risk assets backed by long-term contracts with creditworthy counterparties.

Acquire and develop renewable energy projects, such as wind power and run-of-river hydroelectricity.

Exploit new gas opportunities that complement our current operations, such as Harmattan Co-streaming and additional gas storage.

▶▶ NEXT for gas

Integrated gas businesses provide internal growth opportunities and strengthen overall business

Our gas businesses are interrelated and linked to our power business. This integration, combined with our strong market knowledge, expertise and diversified market presence, creates a stronger AltaGas.

Links between the gas businesses create value, allow us to better manage our risk-reward profile, and provide internal growth opportunities, such as the Cold Lake Orion project.

Opportunities exist to expand, grow and optimize our current infrastructure to increase value and profitability.

Diversified business segments and contracting strategy mitigate exposure to commodity prices

The natural gas business is cyclical. The various parts of AltaGas' gas business balance one another, enabling growth in some areas when others experience weakness.

In 2007 lower natural gas prices and regulatory issues led to lower field gathering and processing activity. These low gas prices and continued high oil prices drove fractionation (frac) spreads to historically high levels that increased profits in our extraction business.

AltaGas' contracting strategy focuses on cost-of-service, fixed-fee and margin-based contract terms with minimal or managed exposure to commodity prices, flowing operating costs through to customers and ensuring recovery of invested capital.

Pursue new gas opportunities that build on and complement our current business

Our growth strategy involves investments in new businesses that capitalize on linkages between our operating experience, market knowledge and financial strength.

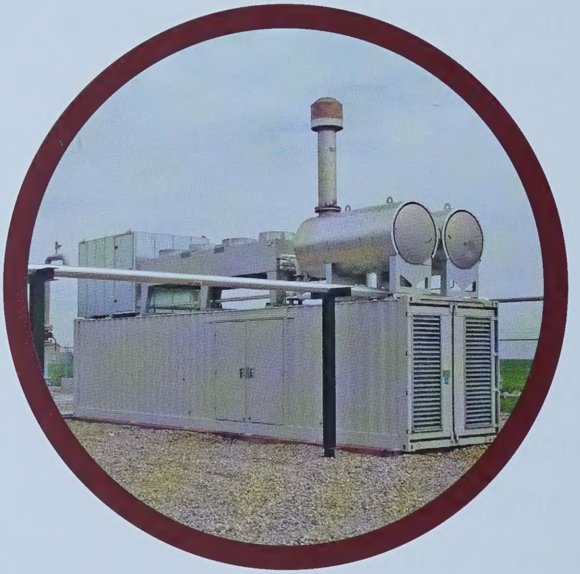
In 2007 AltaGas moved into natural gas storage with the acquisition of an interest in the Sarnia Airport Storage Pool Project, allowing us to participate in the growing demand for storage services. We are pursuing additional storage opportunities.

The acquisition of Taylor provides AltaGas with low-risk, long-life complementary assets that increase diversification and better balance AltaGas' asset base. The acquisition also adds significant growth opportunities, such as Harmattan Co-streaming and consolidation of processing capacity in areas served by these new assets.

Focus on active gas production areas and unconventional gas sources

AltaGas continues to expand, construct and acquire processing facilities. We are primarily focused on prolific areas with strong producer activity, like northwest Alberta and northeast British Columbia, and unconventional gas sources, particularly coal bed methane.



NEXT for power

Successful risk mitigation strategy

AltaGas' strategy is to hedge two-thirds of the Sundance B PPAs' annual output. We continually evaluate opportunities to increase earnings through additional hedging activities as market conditions permit.

We operate our gas-fired peaking plants from our Edmonton extraction facility. These plants ramp up quickly, allowing AltaGas to offer power into the Alberta grid when it is profitable and backstop our coal-fired capacity.

Peaking plants also provide ancillary services to the Alberta power grid – we receive payment for remaining on standby, ready to produce power when dispatched by the grid.

Strong outlook for Alberta power market

Power demand in Alberta remains strong. With limited new generation being built, reserve margins continue to tighten and power prices are expected to remain high for the next few years. This should allow AltaGas to continue hedging at strong prices. In early 2008 forward prices for power in Alberta through 2012 are all in the low to mid-$70/MWh range.

Increase balance and diversification of power generation portfolio

AltaGas is focused on the long-term sustainability of our power business. We are expanding our power portfolio and diversifying by geography and fuel source.

We entered the power business in 2001 with the acquisition of 353 MW of coal-fired generation in Alberta through a 50 percent interest in Sundance B PPAs. Today, we have a power portfolio consisting of coal-fired, gas-fired and hydro generation, with wind power and more hydro facilities under development in B.C.

Expand into renewable energy sources

We aim to capitalize on the growing North American demand for clean power. We are expanding into renewable energy sources, such as wind and run-of-river hydro generation, and increasing our development and operating expertise.

The renewable energy projects we pursue are stable, low-risk projects backed by long-term contracts with creditworthy counterparties and strong supply and demand fundamentals.

Integrate with gas business to provide increased growth opportunities

Our power business is closely linked to our gas business. This integration, combined with our strong market knowledge, expertise and diversified market presence, creates a stronger AltaGas.

The links between our gas and power businesses create value, allow us to better manage our risk-reward profile, and provide internal growth opportunities such as the gas-fired peaking plants, which are operated from our Edmonton extraction facility using gas provided by Energy Services.

David W. Cornhill
Chairman and Chief Executive Officer

Letter to Unitholders

Financial discipline, profitable growth and diversification – that's the way AltaGas does business.

In 2007 we clearly demonstrated the "Energy to Grow" that we had promised. We did what we said we would do, executing our strategy for balanced growth in our two businesses, natural gas and power. We continued to create long-term value for unitholders while maintaining the discipline and focus that got us where we are. AltaGas came out of 2007 with the momentum and ability to achieve what's next: further growth in 2008 and beyond.

Our growth strategy is built upon several essential elements. In expanding our assets, the goal is to achieve balanced growth in the natural gas and power businesses while diversifying the cash flow-generating assets within and among our business segments. Diversification includes moving into renewable energy opportunities. As we implement our growth initiatives we will maintain financial discipline, including a strong balance sheet and investment-grade credit ratings. These elements are aimed at growing AltaGas' net income and cash flows year by year, supporting sustainable cash distributions to our unitholders.

Last year we focused on carrying out our growth strategy. We made excellent progress in a number of areas, including:

- Initiating the acquisition of Taylor NGL Limited Partnership, a $599 million transaction that provides additional growth opportunities while strengthening and diversifying AltaGas in its core businesses.
- Growth in renewable energy, including construction launch of the Bear Mountain Wind Park and initiating the acquisition of our first interest in run-of-river hydroelectric power generation.
- A move into natural gas storage, which will add cash flows and benefit from AltaGas' energy services capabilities in Ontario.
- Continued growth in the natural gas and power businesses, adding 15 Mmcf/d of coal bed methane processing capacity, a 15 Mmcf/d natural gas gathering line and developing an additional 14.4 megawatts (MW) of peaking power capacity.
- Strong financial results, including:
  - Net income of $109 million ($1.90 per unit). Net of SIFT tax, net income was $114 million ($1.99 per unit).
  - Operating income of $127 million, equalling the record set in 2006.
  - Funds from operations of $163 million ($2.84 per unit).
  - Return on equity of 19.8 percent, or 20.7 percent excluding the SIFT tax.
  - Cash distributions of $2.065 per unit, reflecting the increase to monthly distributions made in September, while remaining within our recently lowered targeted payout range of 65 to 75 percent of funds from operations.
  - A strong balance sheet, maintaining the Trust's investment-grade ratings and providing the financial flexibility to grow.

The Gas and Power Businesses

AltaGas' power business continued to grow as planned throughout 2007. Our major asset, the Sundance power purchase arrangements, continued to provide a growing cash flow stream that is substantially price-hedged. With power prices and demand strong in Alberta, we continued to realize value on our existing gas-fired peaking plants. And we will bring two new peaking plants into service early this year. Operating income from the power business increased by 4 percent year-over-year.

AltaGas is able to maintain profitability throughout the commodity price cycle.

Results in the natural gas business reflected AltaGas' risk-mitigation strategy. Field activity in the upstream natural gas industry was dampened by price weakness and regulatory issues. However, by carefully building a business of offsetting segments, implementing contracts that flow operating costs through to customers, pursuing long-term contracts, carefully managing its balance sheet and cultivating a diversified opportunity base, AltaGas is able to maintain profitability throughout the commodity price cycle. Nowhere was this strategy better shown than in our gas business. Although overall gathering and processing throughput fell in 2007, lower natural gas prices and continued high oil prices drove higher fractionation spreads that increased profits in the extraction business. Some of our frac spread exposure was hedged at historically high prices, solidifying cash flows for the next year. With one segment balancing the other, our natural gas business results were down only 6 percent and were offset by the increase in 2007 power results. Through this coordination and balance between the segments, we continued to grow our core natural gas business.

The Taylor acquisition adds low-risk, long-life complementary assets that make AltaGas increasingly diversified and balanced.

Despite recent natural gas price weakness, we remain optimistic about the natural gas business in the Western Canada Sedimentary Basin. We're confident in the ingenuity of Western Canada's energy industry, which is applying bold thinking and creativity to generate new natural gas potential and maximize the basin's reserves. We foresee essentially steady production from Western Canada for many years, creating an environment in which AltaGas can thrive and grow.

Taylor Acquisition

Each of our business efforts in 2007 reflected and advanced our strategy for balanced growth. The largest transaction we undertook in 2007 was the acquisition of Taylor NGL Limited Partnership for $599 million, excluding our pre-existing 9 percent ownership interest. With its strong 2007 performance, we paid approximately 10 times EBITDA for Taylor. AltaGas will benefit from continued high frac spreads, integration, and significant future growth opportunities resulting from the transaction.

Operationally, the Taylor acquisition adds low-risk, long-life complementary assets that make AltaGas increasingly diversified and balanced. The assets have rated economic lives extending as far as 2050 and in many cases are anchored by long-term contracts of up to 40 years, meeting AltaGas' high standards for long asset life and managed risk. These assets substantially increase cash flows in the Extraction and Transmission segment, and provide improved balance across AltaGas' business segments.

Financially, the new assets are immediately accretive to AltaGas' cash flow per unit, add free cash flow (roughly, cash flow available for reinvestment) and are expected to be neutral to accretive to net income per unit in 2008. They also increase AltaGas' liquidity and access to capital; important factors as we plan our approach to the post-2010 income trust world.

Additional Growth

We undertook several other initiatives in 2007 that are aligned with our strategy for balanced growth.

We expanded our gas business in Ontario with the addition of natural gas storage, acquiring a 50 percent partnership position in a storage facility in Sarnia with a working capacity of 5.3 Bcf. Storage is a critical service required by natural gas liquids and petrochemical industries and Sarnia is a key location for these businesses. The project provides steady fee-for-service cash flows that minimize commodity price risk and is expected to be in service in mid-2009. By using the capabilities of the AltaGas Energy Services team in Chatham, Ontario, we can create additional value from this long-life asset. We are also pursuing further natural gas storage opportunities in Ontario and Michigan.

In the gas business we also constructed a new 10 Mmcf/d coal bed methane processing facility in the Horseshoe Canyon formation, acquired a 5 Mmcf/d coal bed methane processing facility in the Mannville formation, both in central Alberta, and acquired a 15 Mmcf/d natural gas gathering line.

In the power business, we began the installation of two additional peaking facilities with combined output of 14.4 MW. Peaking plants are small, natural gas-fired generators used to top up a region's electricity supply in times of maximum demand. The new plants are located at two of our existing field gathering and processing facilities, and all six of our peaking plants will be controlled from our Edmonton extraction

facility. This is an excellent and highly profitable demonstration of integrating our assets and services across our business segments to create additional value. The peaking power business uses existing assets as a base, and improves AltaGas' market presence, physical infrastructure and expertise. This business backstops our coal-fired Sundance power purchase arrangements and is also used to provide backup services to the Alberta power market.

Renewables

AltaGas' careful and deliberate move into renewable energy development is another compelling example of our balanced growth. Renewable energy is helping diversify our power business by energy source and geographic location. With approximately 175 MW of run-of-river hydro and wind power generation under development or construction, we are evolving into a major renewable energy player, particularly in British Columbia.

Renewable energy is helping diversify our power business by energy source and geographic location.

December marked an important milestone, commencing construction of the Bear Mountain Wind Park. I'm proud of Bear Mountain. This $190 million project will have the capacity to produce approximately 100 MW of clean, green power when it enters service in late 2009 - helping BC Hydro meet its commitment of 90 percent of new capacity generated from green sources. The gearless turbines that we ordered from Enercon are efficient, cost-effective and reliable. Bear Mountain will be B.C.'s first wind farm and its output will be sold to BC Hydro under a 25-year, indexed contract. We also own a 25 percent interest in a run-of-river hydroelectric project that generates 7 MW of clean, sustainable electricity backed by a long-term contract with BC Hydro. We have a pair of 40-year contracts with BC Hydro for two 10-MW run-of-river projects which should be in service in 2010, and in February 2008 we announced an additional four potential run-of-river projects totalling approximately 50 MW of capacity.

Financial Performance

The fundamental purpose in executing our growth strategy is to increase our net income and cash flows, and to create long-term value for unitholders. AltaGas had a fantastic year in 2006 with all-time record results, and I'm pleased that in 2007 we were able to meet that performance. Even more important was the way we achieved these results. Since 1994 we have worked to build a business that is viable and strong for the long term. We have a track record of 14 years of increasing cash flows. We focus on mitigating risks and securing long-term revenue streams to make cash flows stable and predictable. As we add new assets and new lines of business, we look for ways to mitigate downsides. We reduce cost exposure and throughput risks in the natural gas business, for example, by structuring services around flowthrough contracts. In extraction we gain exposure to frac spread upside but have downside protection for when these spreads are unfavourable. We underpin our power business with price hedges.

Since 1994 we have worked to build a business that is viable and strong for the long term.

These were the basic, foundational measures selected when we began business. By using them to guide our performance, these measures have helped us create tremendous value over the years. Meanwhile, we added a further layer of risk-mitigation by structuring a diversified overall business, resilient to movements in individual segments. We have delivered on our goal of securing long-term cash flows. Consequently, AltaGas has proven to be a good investment. We increased net income nearly six-fold from 2001 through 2006, and last year matched our record 2006 operating income. These strengths enabled AltaGas to increase its monthly distribution by 3 percent to $0.175 per unit last September, while remaining within our recently lowered targeted payout range of 65 to 75 percent of funds from operations.

People, Safety and Community

People are a key focus at AltaGas – both our employees and those in the communities we operate. The quality of our workforce is one of the three key priorities in our strategic plan. I was pleased to see that in October, AltaGas was again recognized as one of Canada's top 100 employers. It was our sixth year in a row, something only one other organization in Calgary can match. This recognition not only allows us to benchmark ourselves within the business community, but it's a real competitive advantage in attracting the right people. By emphasizing opportunity, challenge and competitive compensation, AltaGas aims to create a favourable work environment, thereby motivating high-quality people to join AltaGas and build careers here.

Our contributions in the communities where we live and operate are focused, carefully selected, and long term. We also provide support to a wide range of organizations on a smaller scale. Our long-term commitments enable us to have a major impact on our partner organizations, the people they support, our employees and the communities around our offices and field facilities. This thinking formed the basis of our five-year, $300,000 commitment to the Alberta-based Shock Trauma Air Rescue Society (STARS) and our ongoing employee and organizational commitment to the United Way.

AltaGas' concern for employees and communities is a clear reflection of our number one core value, safety and environment. The potentially life-saving safety benefits are one reason for our involvement with STARS.Our financial support assisting STARS to acquire new air ambulance helicopters with extended range that can provide rapid response to people in need - including the approximately 350 individuals working at our field facilities in B.C., Alberta and Saskatchewan.

Last year we commenced another multi-year commitment, the sponsorship of Canada's national cross-country ski team. We feel an affinity to this sport's values of focus, discipline and long-term commitment to achieving a goal. These values fit our own culture, and we are pleased to make a four-year commitment totalling more than half a million dollars. These funds will help develop Canada's national cross-country ski team, including the hiring of additional coaches who will focus on building Canada's amateur talent to an internationally competitive level. This national sponsorship also creates coast-to-coast exposure of the AltaGas name, matching our coast-to-coast business presence.

We will remain guided by the core values that have developed AltaGas into what it is today - a market leader and proven innovator

Regulatory

AltaGas' confidence, capabilities, diversified businesses and financial strength provide many benefits, including positioning AltaGas to deal with changes to the fiscal and regulatory environment. New policies from the federal and provincial governments were imposed in 2007 that added higher levels of uncertainty, and created unsupportive impacts on businesses. Key provisions of the higher Alberta oil and natural gas royalties program, announced in general terms last fall and to be implemented in 2009, remain unknown. These questions are expected to continue impacting the energy-producing sector in 2008. Our natural gas producer customers need to know the rules in order to calculate costs and, in turn, to plan their capital programs effectively. Additionally, the provincial government's new policy demanding that industries decrease carbon dioxide emissions intensity, coupled with an as-yet incomplete plan for greenhouse gas credits, creates further uncertainty for Alberta business and all Canadians. It's imperative that governments of all levels provide regulatory clarity in these areas.

We have repeatedly stated that, having thrived as a corporation before our 2004 trust conversion and having a steady focus on the key financial metrics of net income and return on equity - as a leading corporation would - we are comfortable about returning to a corporate structure after 2010, should it make economic sense. AltaGas' business growth, earnings record, distributions strength, comfortable payout ratio, strong balance sheet and tax pools to help shelter future earnings, leave us well-prepared for the post-2010 environment. When the time comes, we will take the path that is best for our unitholders.

What's NEXT

Our business is solid. Since inception just 14 years ago, AltaGas has grown through good vision, strong leadership, oustanding people, the right assets and focus, and investors who get it. We have become a regional energy infrastructure player with transcontinental business. Looking forward, we will continue to balance growth in gas and power. We will continue our focus on renewable energy, and will broaden our reach, both geographic and by fuel source, with investments such as natural gas storage and our significant and leading commitment to renewable energy developments in B.C. and other areas in Canada and the northern United States.

We will remain guided by the core values that have developed AltaGas into what it is today - a market leader and proven innovator. Every asset we build or buy will meet our key criteria and must contribute to creating long-term value for unitholders, while maintaining or improving our risk profile, balance sheet strength and ability to grow net income, funds from operations and return on equity. AltaGas will continue to pursue its goal of growing net income faster than distributions.

Financially we are well-positioned to execute our strategy. With a strong balance sheet, access to credit, increasing free cash flow and a universal shelf prospectus for $500 million in new equity or debt if needed, AltaGas has the resources to grow.

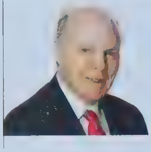
Finally, I would like to express my thanks to every AltaGas employee for their dedication and focus in carrying out AltaGas' strategy for balanced growth throughout 2007 and into 2008. I also welcome the employees and managers of Taylor to our team. The outstanding quality of today's AltaGas team gives me confidence that we will continue creating value for our unitholders tomorrow and well into the future.

On behalf of the Board of Directors,

David W. Cornhill
CHAIRMAN AND CHIEF EXECUTIVE OFFICER

March 3, 2008

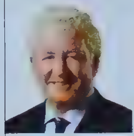
Board Of Directors



David W. Cornhill
CHAIRMAN AND CHIEF EXECUTIVE OFFICER
Member of the EOHSC

Allan L. Edgeworth
DIRECTOR
Independent director;
Member of the AC and EOHSC

Denis C. Fonteyne
DIRECTOR
Independent director;
Chair of the EOHSC and
Member of the HRCC



Daryl H. Gilbert
DIRECTOR
Independent director;
Member of the AC and HR

Corporate

The members of the Board of Directors of AltaGas General Partner Inc. are elected by the Trust at the direction of the unitholders to manage or supervise the management, business and affairs of the Trust. It is our responsibility to ensure that the interests of unitholders and other stakeholders are properly represented. To that end, the Board of Directors has assumed responsibility for stewardship of the Trust and has developed standards and procedures for its operations that meet a high standard of governance. We regularly review the activities of the Trust with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that unitholders expect. We are committed to continuing to direct the activities of the Trust to those high standards.

The annual meeting provides AltaGas' executives with the opportunity to communicate the Trust's goals and strategy to unitholders. The meeting offers unitholders the chance to hear first-hand from management and to understand AltaGas' strategy for seeking to continually increase unitholder value and grow the Trust. The Board of Directors and AltaGas' management team encourage you to attend the annual meeting either in person in Calgary or through the live webcast that can be viewed at www.altagas.ca. The annual meeting will be held at 3:00 p.m. MDT on Thursday, April 24, 2008 at The Metropolitan Centre, Strand/Tivoli Room, 333 – 4th Avenue S.W., Calgary, Alberta.

On behalf of the Board of Directors:

Myron F. Kanik
LEAD DIRECTOR

AltaGas believes that good governance improves performance and benefits all unitholders. AltaGas is committed to a high standard of governance. The following is a summary of the Trust's Governance Practices. A more detailed description of the Trust's practices can be found in the Trust's Information Circular filed on the SEDAR system.

Statement of Governance Practices

Mandate of the Board

The Board of Directors of the General Partner exercises overall responsibility for the management and supervision of the affairs of the Trust. This includes the appointment of the Chief Executive Officer and senior officers of AltaGas Ltd. and AltaGas General Partner Inc., approval of their compensation and monitoring of the Chief Executive Officer's performance.

The Board of Directors also reviews and approves the annual strategic plan. Key objectives, as well as quantifiable operational and financial targets, and processes for the identification, monitoring and mitigation of principal business risks are incorporated into the annual strategy review.

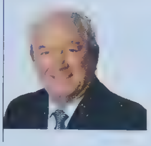
The Board of Directors ensures that a process is established that adequately provides for succession planning, including the appointment, training and monitoring of senior management.

In 2007, the Board of Directors reviewed and ratified the Trust's Disclosure Policy.

Board Composition

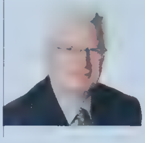
The Board currently comprises eight Directors, seven of whom are independent. David W. Cornhill, Chairman and Chief Executive Officer of AltaGas General Partner Inc., is the only member of the Board of Directors who is also a member of management.

Robert B. Hodgins
DIRECTOR
Independent director;
Chair of the AC and Member of the GC



Myron F. Kanik
LEAD DIRECTOR
Independent director;
Chair of the GC and of the HRCC

David F. Mackie
DIRECTOR
Independent director;
Member of the GC and HRCC



Neil McCrank
DIRECTOR
Independent director;
Member of the GC and EOHSC

governance

Board Committees

The Board has four standing committees: Governance; Audit; Environment, Occupational Health and Safety Commitee; and Human Resources and Compensation. The Governance, Audit and Human Resources and Compensation committees are composed exclusively of non-management, independent directors. The Environment, Occupational Health and Safety Commitee includes a majority of non-management, independent directors. The Chairman and Chief Executive Officer of AltaGas General Partner Inc. serves on the Environment, Occupational Health and Safety Committee. Each of the committees has a Board of Directors-approved mandate that prescribes its composition and responsibilities.

Governance Committee (GC)

The Governance Committee is responsible for reviewing, reporting and providing recommendations for improvement to the Board with respect to all aspects of governance. The Committee is responsible for identifying individuals qualified to become members of the Board of Directors, and recommends to the Board of Directors proposed nominees for election to the Board of Directors. The Committee reviews and recommends compensation for Directors. Annually, the Governance Committee formally assesses the effectiveness of the Board of Directors and the Committees of the Board of Directors. As well, the Committee is responsible for the orientation and education of new members of the Board of Directors and continuing development of existing members of the Board of Directors.

Audit Committee (AC)

The Audit Committee comprises three independent and financially literate Directors who oversee the Trust's financial reporting process on behalf of the Board of Directors. The Audit Committee reviews, reports and provides recommendations to the Board of Directors on the annual and interim financial statements, including the completeness and accuracy of financial reporting of the Trust; the adequacy of risk management processes; the adequacy of its internal control system for financial reporting and disclosure; and the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor. At every Audit Committee meeting, the Committee has the opportunity to meet with the independent and internal auditors without management present.

The Chair of the Audit Committee is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Energy Trust, Treasurer of Canadian Pacific Limited and Chief Financial Officer of TransCanada PipeLines Limited. Mr. Hodgins has the strong financial background crucial to this role.

Environment, Occupational Health and Safety Committee (EOHSC)

The Environment, Occupational Health and Safety Committee is responsible for reviewing, reporting and making recommendations to the Board of Directors on the Trust's policies and procedures with respect to the environment and occupational health and safety.

The Trust is committed to being a steward of the environment and to the health and safety of its employees.

Human Resources and Compensation Committee (HRCC)

The Human Resources and Compensation Committee reviews, reports and provides recommendations to the Board of Directors on the compensation of the Chief Executive Officer and the appointment and compensation of senior corporate officers, succession plans, the compensation policy for all other employees and the approval of all grants of unit options. In 2006, AltaGas adopted a Code of Business Ethics, a copy of which can be viewed on our website. AltaGas is committed to operating its businesses in an ethical manner.

Financial growth

MD&A Contents

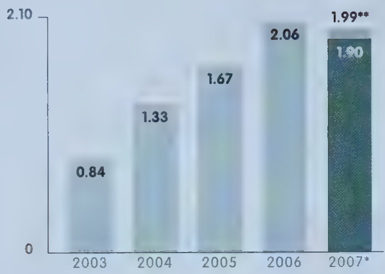
overview

segments

liquidity

other

Net Income per Basic Unit
$



* In 2007 net income per unit included a negative non-cash tax adjustment of $0.09 per unit due to SIFT tax. See discussion beginning on page 24.
** Figure calculated with adjustment due to SIFT tax.

$108.8 million **net income**

Cumulative average growth of 23%

Page 24

Funds from Operations per Basic Unit
$

$162.9 million **funds from operations**

Cumulative average growth of 10%

Page 24

Invested Capital
$ millions

$1.2 billion **total assets**

Total of $456.4 million invested in last five years

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Debt as a Percent of Total Capitalization
%

$220.7 million **total debt**

Below target of 40-45% to support growth strategy

Page 54

2007

key drivers

- **Higher hedged power prices and lower costs more than offset lower spot power prices and the expiration of the Genesee power contract in 2006.**
- **Higher frac spreads and volumes increased Extraction and Transmission results.**
- **Impact of lower throughput in Field Gathering and Processing segment was partially offset by new facilities and higher rates due to recontracting.**
- **Sale of non-core oil and gas production assets.**
- **Higher operating and administrative costs.**
- **Non-cash future income tax benefit of $6.1 million due to reduced federal tax rates mostly offset the $5.4 million SIFT tax.**

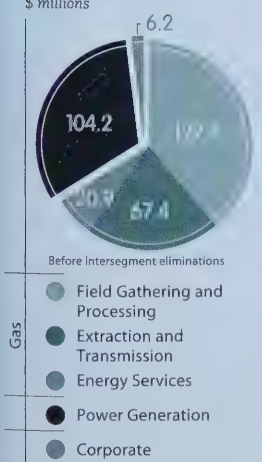
$324.0 million **net revenue**

$173.7 million **EBITDA**

$126.6 million **operating income**

$86.1 million **invested capital**

Net Revenue
$ millions



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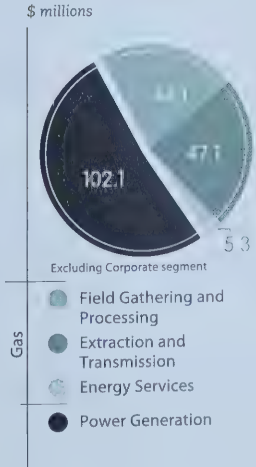
EBITDA
$ millions



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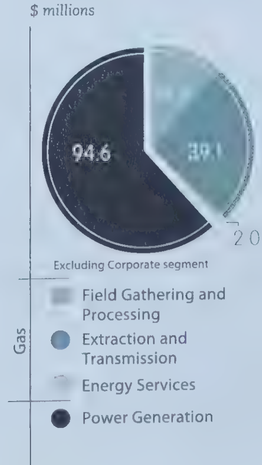
Operating Income
$ millions



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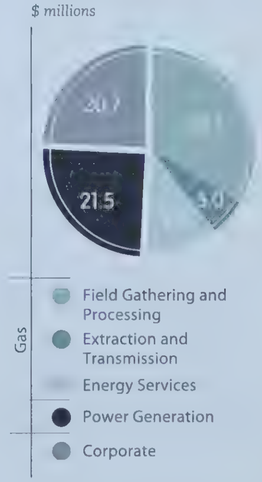
Invested Capital
$ millions



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Management's Discussion and Analysis

The Management's Discussion and Analysis (MD&A) of operations and financial statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Income Trust (AltaGas or the Trust) as at and for the year ended December 31, 2007 compared to 2006. This MD&A dated March 3, 2008 should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of the Trust for the year ended December 31, 2007.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for the purposes other for which it is disclosed herein.

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of the Trust, including its annual MD&A and audited financial statements, Annual Information Form, Information Circular and Proxy Statement, material change reports and press releases issued by the Trust, are also available through the Trust's website or directly through the SEDAR system at www.sedar.com.

ALTAGAS INCOME TRUST

The material businesses of the Trust are operated by AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership, AltaGas Pipelines Partnership, PremStar Energy Canada Limited Partnership and ECNG Limited Partnership (collectively the operating subsidiaries). The cash flow of the Trust is solely dependent on the results of the operating subsidiaries and is derived from operating income earned from partnership interests held by AltaGas Holdings Limited Partnership No. 1 (AltaGas LP #1), from interest earned on loans to the operating subsidiaries and from dividends or returns of capital from equity interests held within the Trust structure.

AltaGas General Partner Inc., through its Board of Directors, the members of which are elected by the Trust at the direction of the holders of the units, has been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. AltaGas Ltd. provides all management, administrative and operating services to the Trust and its subsidiaries.

OVERVIEW OF THE BUSINESS

AltaGas is a gas and power infrastructure business with physical links along the energy value chain, operating experience that has a strong track record of achieving efficiency, reliability and profitability of its assets, knowledge of the markets it serves and the financial discipline to create long-term value for its investors. AltaGas is focused on maximizing the profitability and long-term value of its current assets and growing its energy infrastructure business through the acquisition and development of assets and services that are linked to its existing business.

The gas business is comprised of gathering and processing assets which include natural gas gathering pipelines and processing facilities. The gathering systems move natural gas from producing wells to processing facilities and the processing facilities remove impurities and certain hydrocarbon components from natural gas, in addition to compressing the gas to meet downstream pipelines' operating specifications for transportation. The processing assets also include ethane and natural gas liquids (NGL) extraction and field fractionation facilities. Extraction plants straddle major natural gas transmission pipelines and reprocess the natural gas to extract and recover ethane and NGLs. The gas business also includes natural gas and NGL transmission pipelines. Transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines. Another key component of the AltaGas gas business is the ability to use its market knowledge and expertise to optimize the assets to create value. AltaGas provides energy consulting and supply management services to non-residential end-users, buys and resells energy, gas transportation and storage, and markets gas for producers to further enhance value by optimizing the infrastructure.

The power business consists of 353 MW of coal-fired base-load generation acquired under power purchase arrangements (PPAs). The PPAs are owned through a 50 percent ownership interest in the Sundance B PPAs, giving AltaGas the rights to Sundance B power output and ancillary services until December 31, 2020. The Sundance plant is located 70 km west of Edmonton, Alberta. AltaGas' power generation portfolio also includes the Bear Mountain Wind Park near Dawson Creek, British Columbia, which will have a capacity of approximately 100 MW and is currently under construction, 25 MW of gas-fired power peaking capacity acquired under a capital lease, as well as a 25 percent interest in a 7-MW run-of-river hydroelectric generation capacity through a 25 percent interest in the Boston Bar Partnership. AltaGas owns 14.4 MW of natural gas-fired peaking capacity which is currently being installed at two gas processing sites. AltaGas has an interest through the GreenWing Energy Development Limited Partnership (GEDLP) to develop wind power and gas-fired power generation and has a preferred relationship with a major turbine supplier to develop wind projects in three states in the United States. AltaGas also owns lease rights and agreements to develop approximately 70 MW of run-of-river hydroelectric projects.

Vision

AltaGas' vision is to become the leading Canadian energy infrastructure company with a focus across Canada and the northern United States, by capitalizing on its solid underlying business, operational expertise and financial strength. To achieve its vision, AltaGas will focus on increasing the value and profitability of its existing assets and on growing and diversifying through development and acquisition of gas and power infrastructure.

Strategy

The Trust's strategy is to deliver sustainable and increasing earnings and cash flow from its existing assets as well as from the growth and diversification of its business. It will achieve this by linking the operating experience of its gas and power business with its energy market knowledge and financial discipline and strength. AltaGas expects the growth in its business to be evenly split between gas and power over the long term. The strategy is to enhance value by providing value-added services along the energy value chain of gathering, processing, transporting and marketing of natural gas and the generation and sale of electricity.

By positioning the Trust strategically along the energy value chain, AltaGas links energy producers to energy users. AltaGas pursues opportunities that offer strong financial returns and growth potential and identifies, evaluates and targets opportunities that are accretive to earnings and cash flow and that provide the appropriate balance between risk and return.

Despite the softening in natural gas prices over the past 18 months and uncertainty in the Alberta royalty regime, AltaGas management believes that North America's natural gas producing regions will continue to require significant investment in drilling, gathering and processing assets to support the levels of production needed to meet long-term demand for natural gas as consuming markets continue to compete for supply. Management also believes that the long-term fundamentals of the power business are strong. North American demand for power is expected to continue growing, with an emphasis on renewable power. In Alberta, marginal supply additions, strong economic growth and the upcoming retirement of older thermal power plants will likely continue to result in high power prices. The sound long-term supply and demand fundamentals for gas and power form the basis of AltaGas' strategy.

The Trust's objectives are to:

- Maximize the profitability and long-term value of its existing infrastructure and services;
- Build on the current mix of energy assets and services with a continued focus on predictable, long-term cash flow horizons using cost-of-service, fixed-fee, and margin-based contract terms and with minimal or managed exposure to commodity prices;
- Grow its gas and power infrastructure and related services through consolidations, expansions and acquisitions in Canada and the northern United States;
- Focus on projects that are accretive to earnings and cash flow and exhibit the appropriate risk and return balance;
- Diversify infrastructure by fuel source, contractual terms, exposure to industry cycles and geographic location;
- Focus on expanding its clean energy footprint such as wind and hydroelectric power, as well as natural gas-fired generation;
- Generate green credits through technology such as acid gas injection and renewable projects to decrease environmental impacts and hedge against environmental costs; and
- Maintain the Trust's investment-grade credit ratings.

In 2007 the Trust made significant progress in growing its business through the offer to acquire Taylor NGL Limited Partnership (Taylor), the expansion of current operations and the development of the Bear Mountain Wind Park. The Taylor acquisition, completed on January 10, 2008, created a more balanced and diversified business with the addition of the RET Complex, the Harmattan Complex, the Younger and Joffre extraction plants as well as two NGL pipelines. The Taylor acquisition also included the 25 percent interest in the Boston Bar hydroelectric plant which increased AltaGas' power generation portfolio by 1.8 MW, as well as two run-of-river hydroelectric projects under development with a planned 20 MW of capacity contracted for 40 years with BC Hydro.

The Taylor acquisition is an example of AltaGas' strategy at work. The newly acquired assets are low-risk, long-life energy infrastructure that are underpinned by long-term contracts with strong counterparties providing stable and predictable cash flows. With the acquisition, AltaGas' infrastructure touches more than 2 Bcf/d of natural gas and AltaGas operates four extraction plants serving the Western Canada Sedimentary Basin (WCSB). The contribution from the extraction business will be increased, thereby diversifying revenue sources. The assets also have the appropriate risk profile, with 12 percent of total extraction volumes exposed to commodity price fluctuations while maintaining the opportunity to limit downside risk and shut-in production when frac spreads are low. AltaGas' new interest in the existing hydroelectric generation plant and run-of-river projects under development have expanded its renewable energy footprint.

Specified Investment Flow-Through (SIFT) Tax and Other

On June 12, 2007 the SIFT tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. Prior to this legislation, AltaGas' future income tax liability reflected only those temporary differences in the Trust's subsidiaries that were subject to tax. While net income in 2007 was significantly reduced by this future income tax adjustment, the non-cash future income tax expense had no impact on current cash flows.

In December 2007 the federal government substantively enacted rate reductions which lowered corporate tax rates for the years 2008 to 2012 and beyond. The federal corporate tax rates were reduced from 19.5 percent in 2008 to 15 percent in 2012 and future years. These rate reductions resulted in rate reductions to the trust taxation rate from 31.5 percent as enacted by the federal government in second quarter 2007 for years commencing 2011, to 29.5 percent in 2011 and 28.0 percent thereafter.

AltaGas' management will continue to review and consider alternatives for the most efficient organizational structure for AltaGas. The Trust is registered in Alberta where a corporation is subject to lower overall tax rates than the rate that will apply to trusts in 2011. The federal government has indicated that it will allow corporate conversions to occur on a tax deferred basis but the specific rules have not yet been established. Subject to the tax deferred mechanism being available, AltaGas expects that it will convert to a corporation prior to 2011 but expects to take advantage of the flow-through mechanism of the trust structure until then, unless there are more compelling reasons for converting prior to 2011. AltaGas has always executed its strategy as a tax-efficient corporation and focused on key traditional financial metrics such as earnings per unit and return on equity. It does not rely on the trust structure to sustain its business. Its assets are long-life, low-risk energy infrastructure, the value of which is underpinned by strong energy supply and demand fundamentals. The infrastructure assets generate strong, predictable and sustainable cash flows and are expected to continue to enhance value for all investors over the long term.

2007 Highlights

AltaGas:

- Offered to acquire all the outstanding units of Taylor not previously held by AltaGas. The acquisition was completed on January 10, 2008. The Taylor acquisition increased extraction capacity by 1,040 Mmcf/d, added 140,000 Bbls/d in transmission capacity, doubled extraction volumes produced to approximately 45,000 Bbls/d and increased the Field Gathering and Processing (FG&P) segment's capacity by 150 Mmcf/d. In addition, the Power Generation segment increased with the 25 percent ownership of the 7-MW Boston Bar power plant and acquisition of 20 MW of hydroelectric generation under development;
- Announced its first energy infrastructure investment in Ontario with the 50 percent ownership of the 5.3 Bcf Sarnia Airport Storage Pool Project;
- Invested $28 million in field gathering and processing infrastructure, primarily in coal bed methane producing areas;
- Acquired and commenced installation of 14.4 MW of additional gas-fired peaking capacity at the Bantry and Parkland gas processing facilities;
- Generated net income of $108.8 million ($1.90 per unit) compared to $114.5 million ($2.06 per unit) in 2006. In 2007 net income included $5.4 million related to the tax on income trusts which was substantively enacted in second quarter 2007;
- Reported EBITDA of $173.7 million ($3.03 per unit), up from $173.1 million ($3.12 per unit) in 2006;
- Generated cash from operations of $183.3 million ($3.19 per unit) in 2007 compared to $146.9 million ($2.65 per unit) in 2006;
- Generated funds from operations[1] of $162.9 million ($2.84 per unit) compared to $161.7 million ($2.91 per unit) in 2006;
- Increased monthly distributions by 3 percent from $0.17 to $0.175 beginning with the September distribution;
- Declared and granted a special distribution of one AltaGas Utility Group Inc. (Utility Group) common share for every 100 trust and exchangeable units of AltaGas valued at $0.076 per unit;
- Signed agreements with Aeolis Wind Power Corporation (Aeolis) and Peace Energy Renewable Energy Cooperative (Peace) to exchange their equity interests in Bear Mountain Wind Limited Partnership (BMWLP) for a royalty agreement giving AltaGas 100 percent ownership of BMWLP;
- Entered into an engineering, procurement and construction (EPC) agreement with Enercon GmbH for the wind turbines required for BMWLP. AltaGas also entered into a long-term service and maintenance agreement with Enercon to operate and maintain the turbines; and
- Announced a significant multi-year financial commitment valued at more than $500,000 to support Cross Country Canada. This commitment is the largest philanthropic contribution ever for the Trust and will support the nation's high-performance cross country skiers and fuel their drive to the podium.

[1] Includes financial measures not included under generally accepted accounting principles. Please see discussion in the Non-GAAP Financial Measures section of this MD&A.

CONSOLIDATED RESULTS

Years ended December 31 ($ millions)	2007	2006	2005
Revenue	**1,428.4**	1,362.6	1,502.3
Unrealized gains on risk management	**1.1**	–	–
Net revenue [1]	**324.0**	318.9	296.9
EBITDA [1]	**173.7**	173.1	155.5
EBITDA before unrealized gains on risk management [1]	**172.6**	173.1	155.5
Operating income [1]	**126.6**	126.7	108.1
Operating income before unrealized gains on risk management [1]	**125.5**	126.7	108.1
Net income	**108.8**	114.5	90.3
Net income before tax-adjusted unrealized gains on risk management [1]	**109.3**	114.5	90.3
Net income before tax [1]	**114.7**	113.4	89.0
Total assets	**1,199.8**	1,109.6	1,068.3
Total long-term liabilities	**329.0**	340.5	335.5
Net additions (disposals) of capital assets	**21.8**	70.5	(139.4)
Distributions declared [2] [3]	**118.6**	110.8	100.0
Cash flows			
Cash from operations	**183.3**	146.9	112.3
Funds from operations [1]	**162.9**	161.7	129.0

($ per unit)			
EBITDA [1]	**3.03**	3.12	2.88
EBITDA before unrealized gains on risk management [1]	**3.01**	3.12	2.88
Net income	**1.90**	2.06	1.67
Net income per diluted unit	**1.89**	2.06	1.67
Net income before tax-adjusted unrealized gains on risk management [1]	**1.90**	2.06	1.67
Net income before tax [1]	**2.00**	2.04	1.65
Distributions declared [2] [3]	**2.065**	1.995	1.85
Cash flows			
Cash from operations	**3.19**	2.65	2.08
Funds from operations [1]	**2.84**	2.91	2.39
Units outstanding (millions)			
Weighted average number of units outstanding for the period (basic)	**57.4**	55.5	54.0
Weighted average number of units outstanding for the period (diluted)	**57.4**	55.5	54.1
End of period	**58.1**	56.4	54.6

(1) Non-GAAP financial measure. See discussion in the Non-GAAP Financial Measures section of this MD&A.

(2) Distributions declared of $0.175 per unit per month commencing in August 2007. From August 2006 to July 2007 distributions of $0.17 per unit per month were declared. From March 2006 to July 2006 distributions of $0.165 per unit per month were declared. From August 2005 to February 2006 distributions of $0.16 per unit per month were declared. From January 2005 to July 2005 distributions of $0.15 per unit per month were declared.

(3) Excludes share distribution of AltaGas Utility Group Inc. shares in September 2007 providing an additional non-cash distribution of $0.076 per unit. Excludes share distribution as a result of the spin-out of the Natural Gas Distribution (NGD) segment in November 2005, providing an additional non-cash distribution of $0.54 per unit.

2007 Consolidated Financial Review

Net income in 2007 was $108.8 million compared to $114.5 million in 2006. Excluding the SIFT tax of $5.4 million recorded in 2007, the $6.1 million non-cash tax benefit due to the reduced federal tax rates recorded in fourth quarter 2007, and the non-cash tax benefit of $6.6 million due to tax rate reductions recorded in 2006, net income for the year ended December 31, 2007 was in line with 2006. Adjusting for these one-time tax items, net income was $108.1 million in 2007 compared to $107.9 million in 2006. Net income increased mainly due to higher power prices received on hedged

sales and lower costs in the Power Generation segment, new facilities and higher rates in the FG&P segment, higher extraction volumes exposed to frac spreads, higher frac spreads, a one-time gain from the sale of oil and gas production assets and lower interest expense. These increases were offset by lower revenues from unhedged sales due to lower Alberta spot power prices, lower throughput in the FG&P segment, the expiration of the Genesee power contract, higher operating and administrative costs, lower earnings in the Energy Services segment and a one-time charge related to non-recoverable costs incurred on a development project.

Consolidated net revenue for 2007 was $324.0 million compared to $318.9 million in 2006. The increase was due to higher hedge prices and lower costs in the Power Generation segment, new facilities and higher rates in the FG&P segment, higher frac spread-exposed volumes and higher frac spreads, and a one-time gain on the sale of oil and natural gas production assets. The increases were partially offset by the expiration of the Genesee power contract, lower throughput in the FG&P segment, a lower contribution from the oil and gas assets sold in May 2007 and decreased earnings in the Energy Services segment.

Operating and administrative expense for 2007 was $150.3 million compared to $145.8 million in 2006. The increase was due to additional costs related to new facilities, higher compensation and administrative costs and a one-time charge related to non-recoverable costs incurred on a development project.

Amortization expense for 2007 was $47.1 million compared to $46.4 million in 2006. The increase was primarily due to new and expanded facilities in the FG&P segment, partially offset by the sale of oil and natural gas production assets and the one-time write down of $0.6 million of goodwill on a non-core investment in 2006.

Interest expense in 2007 was $11.9 million compared to $13.3 million in 2006. The decrease was primarily due to a lower average debt balance of $234.9 million compared to $274.1 million in 2006, partially offset by slightly higher borrowing rates. The average borrowing rate in 2007 was 5.3 percent compared to 4.9 percent in 2006.

Income tax expense for 2007 was $5.9 million compared to an income tax recovery of $1.1 million in 2006. The increase was mainly due to the non-cash charge of $5.4 million to record future income tax liabilities for differences between the accounting and tax basis of AltaGas' assets and liabilities as a result of the SIFT tax, the $6.6 million non-cash tax benefit recorded in 2006 due to Alberta and federal income tax rate reductions and a $1.6 million tax impact on unrealized gains related to risk management assets and liabilities. These increases were partially offset by the difference between the $6.1 million non-cash tax benefit due to the federal rate reductions enacted in late 2007 and the future income tax recovery of $0.6 million from the sale of oil and natural gas production assets.

2008 Consolidated Outlook

With the addition of the new assets to AltaGas' current energy infrastructure and services business, AltaGas expects to deliver a significant increase in earnings and cash flow in 2008. The majority of the acquired assets will be included in the Extraction and Transmission (E&T) segment. AltaGas expects the proportion of its operating income from this segment to increase from 25 percent of overall operating income from all business segments in 2007 to approximately 40 percent in 2008.

In 2008 AltaGas expects operating income to increase as a result of the contribution of the new assets from the Taylor acquisition, higher hedge prices for power and continued strong frac spreads. The current forward curve for Alberta spot power prices is in the low to mid-$70/MWh range, higher than the average Alberta Pool price for 2007. NGL volumes produced are expected to double year-over-year resulting in NGL volumes exposed to frac spreads increasing from approximately 9 percent of total volumes in 2007 to 12 percent in 2008. The current forward curve for frac spread is in the low to mid-$20/Bbl range.

2006 Consolidated Financial Review

This section provides an overview of AltaGas' financial performance based on the audited annual Consolidated Financial Statements included in the 2006 Annual Report. All references to per unit amounts pertain to basic units outstanding for the period. Certain prior-year figures have been reclassified to conform to the current year's presentation.

Net income in 2006 was $114.5 million ($2.06 per unit) compared to $90.3 million ($1.67 per unit) in 2005. The increase was due to higher power prices received on both hedged and unhedged power volumes, lower power transmission costs, higher NGL frac spreads, higher extraction volumes and lower interest expense, partially offset by higher operating and administrative expense and higher income taxes.

In addition the Trust recorded a $6.6 million non-cash future income tax benefit in 2006 as a result of a reduction in federal and Alberta corporate income tax rates. Net income in 2005 included one-time contributions of $7.5 million related to the Trust's ownership of Taylor units, a full-year contribution from the Genesee power contract and the contribution from the Natural Gas Distribution (NGD) segment which was spun out on November 17, 2005.

Net revenue for 2006 was $ 318.9 million compared to $296.9 million in 2005. The increase was mainly due to higher prices received on the sale of power and lower power transmission costs ($42.2 million), new facilities, higher processing fees and higher operating cost recoveries in the FG&P segment ($15.1 million), higher NGL frac spreads and higher volumes processed in the extraction business ($7.0 million), higher equity earnings in the Corporate segment ($3.0 million), the acquisition of the assets and liabilities of iQ2 Power Corporation (iQ2) in late 2005 ($2.2 million) and $2.1 million higher net revenue from the gas-fired peaking plants. The increases in net revenue were partially offset by the spin-out of the NGD business in November 2005 ($29.0 million), lower throughput in the FG&P segment ($5.2 million), the expiration of the Genesee power contract in March 2006 ($2.5 million) and $1.6 million lower contribution from the oil and gas properties. In 2005 net revenue included one-time contributions of $8.6 million related to the Trust's ownership of Taylor units.

Operating and administrative expense for 2006 was $145.8 million, compared to $141.4 million in 2005. The increase was due to higher administrative and compensation costs, additional costs from new FG&P facilities and the acquisition of iQ2. The increases were partially offset by the spin out of the NGD segment which reported operating and administrative costs of $16.0 million in 2005. Increased third-party costs of approximately $1.0 million were incurred in 2006 over 2005 to meet new certification requirements for reporting issuers mandated by the Canadian Securities Administrators.

Amortization expense for 2006 was $46.4 million compared to $47.4 million last year. The decrease was due to the spin out of the NGD segment which reported $6.8 million in amortization expense in 2005, partially offset by increases related to the growth in capital assets resulting from acquisitions and internal expansion projects, higher depletion expense related to the Trust's oil and gas properties and higher amortization related to energy services contracts and relationships. In 2006 AltaGas also recorded a goodwill impairment of $0.6 million related to a non-core investment.

Interest expense in 2006 was $13.3 million compared to $19.1 million in 2005. The decrease was due to lower average debt balances (2006 – $274.1 million, 2005 – $326.1 million) as a result of $85.4 million in debt repayment in late 2005 using the proceeds from the spin-out of the NGD segment and due to higher funds from operations. Also contributing to the lower interest expense was a lower average borrowing rate of 4.9 percent in 2006, compared to 5.6 percent in 2005, mainly due to the August 2005 refinancing of term debt at lower rates.

Income tax recoveries for 2006 were $1.1 million compared to recoveries of $1.3 million in 2005. Income tax recoveries decreased as a result of higher net income before tax in 2006, partially offset by a non-cash future tax benefit of $6.6 million that resulted from federal and Alberta income tax reductions in 2006. Income taxes reported in 2005 also included an expense of $1.1 million related to the NGD segment, an adjustment of future tax balances that resulted in a recovery of $1.6 million and a lower effective tax rate in respect of the Taylor capital gain reported in 2005.

Capital Outlook

AltaGas' strategy is to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. In order to execute its strategy, AltaGas expects capital expenditures to be approximately $125 million and $250 million in 2008 and 2009 respectively and to be split approximately 60 percent gas and 40 percent power in both years. Included in the estimated expenditures is approximately $50 million annually for gas infrastructure projects. This estimate is based on projects that are in various stages of development and historical levels of expenditures in the FG&P segment. The estimate does not include the cost of developing the four potential run-of-river projects described below.

Bear Mountain Wind Park

AltaGas currently owns 100 percent interest of the BMWLP and the Bear Mountain Wind Park. AltaGas intends to finance the project, which is expected to cost approximately $190 million, through its credit facilities and by including one or more third-party investors in the project, which would reduce AltaGas' ownership in the wind park to approximately 45 percent. The Bear Mountain Wind Park will have a capacity of approximately

100 MW and is backstopped by a 25-year electricity purchase agreement with BC Hydro. AltaGas entered into an EPC agreement with Enercon to supply and install wind turbines. AltaGas has also entered into a long-term service agreement with Enercon to operate and maintain the wind turbines. AltaGas commenced construction activities in December 2007 and intends to have the project completed by November 2009. Expenditures for 100 percent of the project are expected to be approximately $55 million in 2008 and $120 million in 2009. AltaGas has hedged approximately 21 percent of the total euros required for the project.

Sarnia Airport Storage Pool Project

AltaGas owns a 50 percent interest in the Sarnia storage project, with the other 50 percent being owned by Market Hub Partners Canada L.P., a Spectra Energy Corp. partnership. The project is expected to provide more than 5 Bcf of working capacity and deliverability of approximately 52 Mmcf/d and will include three new wells, a compressor plant and approximately 18 kilometres of pipeline. The project is in the early stages of development, is subject to various regulatory and environmental approvals and is expected to be in full operation by mid-2009. AltaGas' share of the project is expected to cost approximately $25 million.

Log Creek and Kookipi Creek Hydroelectric Projects

AltaGas is developing two hydroelectric facilities to be located on the Fraser River near Hope, British Columbia. The Log Creek and Kookipi Creek projects are each 10-MW run-of-river hydroelectric facilities in the final stages of permitting and licensing. Both facilities have 40-year electricity purchase agreements with BC Hydro. The plants are expected to be in operation in 2010 and to cost a total of approximately $60 million to $70 million.

Run-of-River Hydroelectric Plants Under Development

In February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. The projects provide AltaGas with the ability to develop approximately 50 MW of hydroelectric power generation in British Columbia. The four new projects are at various stages of development, with the 14 MW Rainy River project near Gibson, British Columbia in an advanced development stage. Rainy River is expected to be operational in 2010. AltaGas anticipates the power from its hydro projects will be sold to B.C. Hydro through its Clean Power Call process. All of the development projects are subject to various regulatory and environmental approvals.

Harmattan Co-Streaming Project

The proposed Harmattan Co-streaming Project is expected to bring natural gas from TransCanada's Alberta system to the Harmattan Complex for processing to recover ethane, propane, butane and condensate. The Harmattan Co-streaming Project hearing at the Alberta Energy Resources Conservation Board (ERCB) is pending the outcome of the inquiry into the NGL extraction convention (the Inquiry). The Inquiry is anticipated to be completed by the fall of 2008. Upon approval, construction of the co-streaming project will commence, requiring approximately 12 months to complete. The project, as currently envisioned, is expected to cost in the range of $70 million to $90 million.

TAYLOR NGL LIMITED PARTNERSHIP 2007 RESULTS

AltaGas acquired all outstanding units of Taylor it did not already own effective January 10, 2008. The results described below are intended to provide the reader with a brief description of Taylor's 2007 results of operations to allow the reader to determine the potential impact of the Taylor acquisition on the results of the Trust.

In 2007 Taylor recorded a net loss of $42.1 million compared to net income of $28.7 million in 2006. Adjusting for the SIFT tax of $69.1 million, the impact of mark-to-market accounting for financial instruments loss of $5.9 million and gain of $0.8 million in 2007 and 2006 respectively and compensation costs of approximately $1 million related to the offer by AltaGas to acquire the units of Taylor, net income in 2007 was $33.9 million compared to $27.9 million in 2006.

Taylor recorded net revenue of $109.9 million in 2007 compared to $101.9 million in 2006. NGL sales averaged 21,126 Bbls/d in 2007 compared to 20,465 Bbls/d in 2006, up 3 percent and setting a new annual record. Gas volumes processed were 443 Mmcf/d in 2007, compared to 452 Mmcf/d in 2006.

Operating and administrative expense in 2007 was $51.2 million compared to $48.1 million in 2006. Included in 2007 was approximately $1 million in higher compensation costs related to the offer by AltaGas to acquire the units of Taylor.

In 2007 Taylor's EBITDA was $59.6 million compared to $53.8 million in 2006, excluding the impact of mark-to-market gains and losses on financial instruments and one-time compensation costs related to the offer by AltaGas to acquire the units of Taylor.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and may not be comparable to similar measures presented by other funds or entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated consistent with previous disclosures by AltaGas.

Net Revenue ($ millions)		2007	2006	2005
Net revenue		**324.0**	318.9	296.9
Add:	Cost of sales	**1,104.4**	1,043.7	1,205.4
Revenue (GAAP financial measure)		**1,428.4**	1,362.6	1,502.3

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, as changes in the market price of natural gas and power affect both revenue and cost of sales.

Operating Income ($ millions)		2007	2006	2005
Operating income		**126.6**	126.7	108.1
Add (deduct):	Interest	**(11.9)**	(13.3)	(19.1)
	Income taxes	**(5.9)**	1.1	1.3
Net income (GAAP financial measure)		**108.8**	114.5	90.3

Operating income is a measure of the Trust's profitability from its principal business activities prior to how these activities are financed or how the results are taxed. Operating income is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses and amortization.

Operating Income Before Unrealized Gains on Risk Management ($ millions)		2007	2006	2005
Operating income before unrealized gains on risk management		**125.5**	126.7	108.1
Add (deduct):	Unrealized gains on risk management	**1.1**	–	–
	Interest	**(11.9)**	(13.3)	(19.1)
	Income taxes	**(5.9)**	1.1	1.3
Net income (GAAP financial measure)		**108.8**	114.5	90.3

Operating income before unrealized gains on risk management is a measure of the Trust's profitability from its principal business activities prior to accounting for how these activities are financed, how the results are taxed, and how the impact of gains from risk management activities affected operations. Operating income before unrealized gains on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gains on risk management less operating and administrative expenses and amortization of capital assets.

EBITDA ($ millions)		2007	2006	2005
EBITDA		**173.7**	173.1	155.5
Add (deduct):	Amortization and goodwill impairment	**(47.1)**	(46.4)	(47.4)
	Interest	**(11.9)**	(13.3)	(19.1)
	Income taxes	**(5.9)**	1.1	1.3
Net income (GAAP financial measure)		**108.8**	114.5	90.3

EBITDA is a measure of the Trust's operating profitability. EBITDA provides an indication of the results generated by the Trust's principal business activities prior to how these activities are financed, how assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses.

EBITDA Before Unrealized Gains on Risk Management ($ millions)	2007	2006	2005
EBITDA before unrealized gains on risk management	**172.6**	173.1	155.5
Add (deduct): Unrealized gains on risk management	**1.1**	–	–
Amortization and goodwill impairment	**(47.1)**	(46.4)	(47.4)
Interest	**(11.9)**	(13.3)	(19.1)
Income taxes	**(5.9)**	1.1	1.3
Net income (GAAP financial measure)	**108.8**	114.5	90.3

EBITDA before unrealized gains on risk management is a measure of the Trust's operating profitability. EBITDA before unrealized gains on risk management provides an indication of the results generated by the Trust's principal business activities prior to accounting for the impact of unrealized gains from risk management activities and how business activities are financed, how assets are amortized or how the results are taxed. EBITDA before gains on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gains on risk management less operating and administrative expenses.

Net Income Before Tax-Adjusted Unrealized Gains on Risk Management ($ millions)	2007	2006	2005
Net income before tax-adjusted unrealized gains on risk management	**109.3**	114.5	90.3
Add (deduct): Unrealized gains on risk management	**1.1**	–	–
Income tax expense on risk management	**(1.6)**	–	–
Net income (GAAP financial measure)	**108.8**	114.5	90.3

Net income before tax-adjusted unrealized gains on risk management is a better reflection of performance than net income as changes related to risk management are based on estimates related to commodity prices and foreign exchange rates over time. Net income before tax-adjusted unrealized gains on risk management is calculated from the Consolidated Statement of Income and Accumulated Earnings and is defined as net income plus unrealized gains on risk management and less income tax expense.

Net Income Before Tax ($ millions)	2007	2006	2005
Net income before tax	**114.7**	113.4	89.0
Add (deduct): Income taxes	**(5.9)**	1.1	1.3
Net income (GAAP financial measure)	**108.8**	114.5	90.3

Net income before tax is a better reflection of performance because it is not dependent on how those results are taxed which can change from year-to-year. Net income before tax is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net income less income tax expense.

Funds From Operations ($ millions)	2007	2006	2005
Funds from operations	**162.9**	161.7	129.0
Add (deduct): Net change in non-cash working capital and asset retirement obligations settled	**20.4**	(14.8)	(16.7)
Cash from operations (GAAP financial measure)	**183.3**	146.9	112.3

Funds from operations is used to assist management and investors in analyzing operating performance without regard to changes in the Trust's non-cash working capital in the period. Funds from operations as presented should not be viewed as an alternative to cash flow from operations or other cash flow measures calculated in accordance with Canadian GAAP. Funds from operations is calculated from the Consolidated Statements of Cash Flows and is defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement costs.

RESULTS OF OPERATIONS BY SEGMENT

Operating Income ($ millions)	2007	2006
Field Gathering and Processing	**18.2**	25.4
Extraction and Transmission	**39.1**	35.2
Power Generation	**94.6**	90.9
Energy Services	**2.0**	2.8
Corporate	**(27.3)**	(27.6)
	126.6	126.7
Operating income before unrealized gain on risk management	**125.5**	126.7

FIELD GATHERING AND PROCESSING

The FG&P segment consists of 77 gathering and processing facilities in 30 operating areas in western Canada and approximately 6,500 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets.

This segment includes the RET complex which is comprised of three interconnected processing facilities and related gathering systems that were acquired effective January 10, 2008 through Taylor. Subsequent to the Taylor transaction, AltaGas has a total gross licensed processing capacity of 1.2 Bcf/d, including 359 Mmcf/d of sour gas capacity. AltaGas operates 74 of its 77 facilities.

77
facilities in 3 provinces within the WCSB.

The gathering systems move natural gas on behalf of producers from the wellhead to AltaGas processing facilities where impurities and certain hydrocarbon components are removed and the gas is compressed to meet the operating specifications of downstream pipeline systems that deliver gas to domestic and export energy markets. AltaGas focuses on owning and operating smaller, moveable natural gas processing facilities with processing capacity of under 50 Mmcf/d, which distinguishes it from most of its competitors in western Canada.

The FG&P segment's main business drivers are throughput, gathering and processing fees and operating costs. Throughput is impacted by new well tie ins, reactivations, recompletions, well optimizations performed by producers and natural production declines in areas served by AltaGas' processing facilities.

Results of Operations

Financial Results ($ millions)	2007	2006
Revenue	**135.1**	139.1
Net revenue	**127.4**	129.7
Operating and administrative expense	**83.3**	80.1
Amortization expense	**25.9**	23.6
Goodwill impairment	**–**	0.6
Operating income	**18.2**	25.4

Operating Statistics	2007	2006
Capacity (Mmcf/d) [1]	**1,023**	1,021
Throughput (gross Mmcf/d) [2]	**511**	549
Throughput (gross annual Mmcf/d) [2]	**527**	555
Capacity utilization (percent) [3]	**52**	54
Average working interest (percent) [1]	**91**	92

(1) As at December 31.

(2) Fourth quarter average.

(3) Average for the period.

AltaGas Field Gathering and Processing Assets

As at March 3, 2008.

In the FG&P segment, operating income was $18.2 million in 2007 compared to $25.4 million in 2006. The decrease was due to lower throughput ($7.6 million), lower equalization and minimum volume adjustments ($3.1 million), higher general and administrative costs ($1.0 million) and higher amortization due to expansions ($0.6 million). The decreases were partially offset by the contribution from new plants ($2.7 million) and higher rates and other revenues of $2.4 million.

Capacity increased due to the addition of the new Acme and Corbett Creek facilities, which were partially offset by the sale of the Ikhil Joint Venture and the redeployment of the Del Bonita assets. Throughput in 2007 averaged 527 Mmcf/d compared to 555 Mmcf/d in 2006. The 5 percent decrease was primarily due to natural declines and lower producer activity, partially offset by new facility throughput additions of 11 Mmcf/d from AltaGas' new Clear Prairie, Clear Hills, Princess and Acme facilities. Of the 28 Mmcf/d throughput decrease, 16 Mmcf/d was attributable to the North district and the balance to the South district. In the North district, the Wabasca area experienced throughput declines of 9 Mmcf/d as a result of a less successful drilling program than the previous year. The decline in the South district was due to lower producer activity, partially offset by higher throughput from new wells at South Foothills. Utilization in 2007 was 52 percent compared to 54 percent reported in 2006.

Net revenue in the FG&P segment in 2007 was $127.4 million compared to $129.7 million in 2006. New facilities contributed $6.1 million to net revenue in 2007, and increased rates contributed $1.5 million. These increases were offset by lower throughput which resulted in a $7.6 million decline in net revenue and lower routine equalization adjustments of $1.7 million.

Operating and administrative expense in the FG&P segment in 2007 was $83.3 million compared to $80.1 million in 2006. The increase was mainly attributable to new facilities, higher property taxes and higher compensation costs, partially offset by lower operating costs.

Amortization expense in the FG&P segment in 2007 was $25.9 million compared to $24.2 million in 2006. The increase was due to new and expanded facilities, partially offset by the sale of the interest in the Ikhil Joint Venture and the write-off of goodwill in fourth quarter 2006.

FG&P Outlook

With the purchase of Taylor completed in January 2008, FG&P will integrate the RET Complex into its FG&P operations. The RET Complex is composed of three interconnected natural gas processing facilities approximately 40 km north of Lethbridge. The RET Complex is capable of handling both sour and sweet natural gas and provides gathering and processing services to approximately 55 producers having approximately 1,200 producing wells. Throughput in the RET Complex averaged 57 Mmcf/d in the fourth quarter of 2007.

FG&P expects to report higher results in 2008 than in 2007. The increase is due to the addition of the RET Complex, recontracting at higher rates, optimization of facilities and increased operating cost flowthrough. AltaGas expects throughput to increase in 2008 over 2007 primarily due to the addition of the RET facilities.

AltaGas is working with customers to optimize underutilized assets. The underutilized Sedgewick facility is expected to be connected to the fully utilized Killam and Iron Creek facilities to allow gas to be diverted to Sedgewick and allow increased combined processing for the three facilities. AltaGas expects to increase its gas gathering and processing infrastructure in 2008 through acquisition and development of new facilities as producers reallocate capital from processing to their core activity of exploration and production. Increased drilling activity and producer activity in CBM areas, northwest Alberta and northeast British Columbia is also expected to provide opportunities for expansions, acquisitions and development of gas gathering and processing infrastructure. AltaGas expects to spend approximately $50 million to grow and optimize its gathering and processing infrastructure in 2008, including gathering systems, capacity expansions and enhancements to its sour gas processing facilities.

AltaGas has experienced declining throughput primarily due to lower drilling activity and natural declines. Producer activity has been impacted by lower profitability and uncertainty regarding the new Alberta royalty regime. In 2008 AltaGas expects producer activity to rebound since average operating costs have declined, natural gas prices remain above the lows of 2007 and the completion of the Alberta royalty review should bring greater certainty to the industry. As a result, AltaGas expects demand for gathering and processing facilities to increase, thereby mitigating the impact of natural declines.

Business Strategy and Opportunities

The FG&P segment provides safe and reliable gathering and processing and ancillary services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share, servicing Alberta's future CBM production and moving westward to capitalize on increased exploration and drilling activities. While the WCSB is considered to be a maturing basin, AltaGas remains confident in the long-term demand for natural gas, strong natural gas prices and improvements in exploration and drilling technology and hence the long-term viability of the WCSB.

AltaGas' strategy is to:

- Maximize the profitability of the current field gathering and processing infrastructure:
  - Increase revenues by converting contracts to flowthrough operating costs and market based fees;
  - Offer flexible contractual terms and equal access to all producers;
  - Enhance operational efficiencies through consolidation, plant upgrades and integration with other business segments;
  - Integrate operational support for the peaking power plants; and
  - Manage costs and improve reliability.
- Grow its field gathering and processing infrastructure:
  - Expand into areas of unconventional gas production such as CBM, shale gas, and tight gas, where dedicated infrastructure is required to meet processing needs;
  - Expand into areas of high producer activity where there is increasing demand for gas gathering and processing infrastructure such as northwest Alberta and northeast British Columbia;
  - Invest in moveable assets that can be easily and quickly redeployed to new locations, improving operational flexibility and profitability, and responding quickly to producer requirements;
  - Increase working interests to control operations, increase efficiency and reduce operating costs;
  - Acquire underutilized assets that offer upside through increased throughput in areas where production is expected to support the investment; and
  - Construct or acquire and connect complementary facilities to create large facility complexes to capture operating synergies.

There are many opportunities to allow AltaGas to execute its strategy in the FG&P segment to meet the existing and future gathering and processing needs of its customers. In addition to its network of approximately 6,500 km of gathering lines, substantial processing capacity, expansion potential and access to downstream transportation pipelines that offer customers diverse marketing opportunities, approximately 80 percent of the compression units are skid-mounted. This allows AltaGas to relocate units quickly and cost effectively to respond to the changing processing needs of its customers. At present, the majority of gathering and processing infrastructure in western Canada is owned by oil and natural gas producers with 15 to 20 percent of the volumes in the WCSB processed by independent gas processors, including 3 percent processed by AltaGas. AltaGas believes that its strong operating skills and moveable assets create opportunities to work with customers to provide field gathering and processing services in a cost-effective and efficient manner.

New area development comes in large part from the drilling programs of AltaGas' existing and expanding customer base. Reserves analysis indicates that there are significant opportunities to increase natural gas production, including unconventional reserves within the WCSB, many in areas where gathering and processing infrastructure is limited thus providing opportunities for new infrastructure investment.

AltaGas may also see increased opportunities to acquire or build gathering and processing infrastructure from or on half of producers wishing to redeploy capital on exploration and production activities rather than on non-core activities such as processing.

Existing field gathering and processing areas usually have adjoining or overlapping gathering and processing systems. As AltaGas has grown, opportunities to expand by tying in new wells and building or purchasing adjoining facilities and systems have increased.

AltaGas also enhances the value of its gathering and processing infrastructure by integrating with the other business segments. The resulting suite of integrated services such as natural gas transmission, NGL extraction and natural gas and NGL marketing enhances value for its customers and investors.

Risk Management

AltaGas' field gathering and processing facilities process or transport natural gas from the WCSB. Throughput at these facilities is dependent on a number of factors including the level of exploration and development within the WCSB, the long-term supply and demand dynamics for natural gas which impact the longer-term price of natural gas, and the regulatory environment for natural gas market participants. Consequently, AltaGas may be exposed to declining cash flows and profitability arising from reduced natural gas throughput and from rising operating costs. AltaGas manages its exposure to financial risk in the FG&P segment using the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Volume declines in the WCSB	• Contract provisions such as take-or-pay, capital cost recovery, area of mutual interest, geographic franchise with economic out, length of term and type of service as well as underpinned capital commitments.	• New contracts in 2007 included take-or-pay provisions. • New facilities and expansions underpinned by take-or-pay contracts. • $2.5 million in take-or-pay shortfall revenue in 2007. • 29 of 30 operating areas have area of mutual interest provisions.
	• AltaGas owns extensive gathering systems and moveable processing plants and can quickly deploy assets in response to customers' drilling activity and volume variability.	• Approximately 80 percent of compression units are skid-mounted. • Relocated six compressors to optimize horsepower and reduce expenses in Cold Lake area. • In response to producer activity, AltaGas relocated approximately 40 pieces of equipment in 2007.
	• Increase geographic and customer diversity to reduce exposure to any one customer or area of the WCSB.	• Approximately 250 customers with no customer representing more than 6 percent of FG&P net revenue during 2007. • Top 10 customers represented 13 percent of consolidated net revenues in 2007. • 77 natural gas processing facilities in 30 operating areas in three provinces within the WCSB. • Developed new Acme facility to process CBM.
	* Expand into areas with strong producer activity, new sources of supply (including unconventional) and limited or fully utilized processing facilities.	• Built Acme plant and acquired Corbett Creek plant and associated gas gathering systems. These facilities are dedicated to processing CBM gas. • Acquired three facilities in southern Alberta through the Taylor acquisition in an area not previously served by AltaGas.
Increasing operating costs	• Contractual provisions provide for recovery of actual operating costs. • Acquire large working interests and operate facilities in order to control and optimize operations, and maximize efficiencies, customer demand and throughput.	• 79 percent of contracts include CPI escalators. • 39 percent of operating costs were recovered directly from customers in 2007. • Increased operating cost flowthrough contracts to recover 45 to 50 percent of operating costs in 2008. • Operating costs remained flat in 2007. • Average working interest of 91 percent. • Operate 74 of 77 FG&P facilities.
Natural gas price fluctuations	• Toll-for-service structure independent of commodity prices; revenues are a function of volumes processed.	• The majority of processing contracts are volumetric service fee structures, based on a rate per Mcf of throughput.
Environmental and safety	• AltaGas has strong safety and environmental management systems, which it continually strives to improve.	• Princess and Turin gas plants continued acid gas injection, reducing carbon dioxide and sulphur dioxide emissions to virtually zero.
Government and regulatory changes	• Regulatory and commercial personnel work closely to monitor and react to regulatory issues.	• Active participation in industry committees and regulatory forums. • Increased activity by CBM producers due to the new Alberta royalty regime increasing demand for AltaGas processing facilities.

EXTRACTION AND TRANSMISSION

The Extraction and Transmission segment consists of interests in four ethane and NGL extraction plants, one fractionation facility, five natural gas transmission systems and one condensate pipeline. The Taylor acquisition in January 2008 added one wholly owned extraction plant and two NGL pipelines in Alberta, increased AltaGas' ownership in the Joffre plant from 50 percent to 100 percent and added interests in an extraction plant in British Columbia.

Extraction

Ownership in 6 of the 10 Canadian extraction facilities.

AltaGas owns extraction plant processing capacity through its interest in two extraction plants at Empress, Alberta, an extraction plant at Joffre, Alberta and another in Edmonton, Alberta. Also included in the extraction business is AltaGas' Bantry field fractionation facility. The extraction plants provide stable fixed-fee or cost-of-service type revenues and margin based revenues. AltaGas' net raw gas licensed inlet capacity at these plants was 554 Mmcf/d at December 31, 2007. With the Taylor transaction effective January 10, 2008, AltaGas added the Harmattan Complex in Alberta, ownership interest in the Younger Extraction Plant in British Columbia and increased its ownership of the Joffre Extraction Plant in Alberta to 100 percent. The Harmattan Complex has natural gas licensed inlet capacity of 490 Mmcf/d, a deep cut NGL extraction unit, NGL fractionation net capacity of 25,000 Bbls/d and NGL terminal facilities. The Younger Extraction Plant, with NGL extraction ownership of 56.7 percent, has net processing capacity of 425 Mmcf/d and NGL fractionation and terminal ownership of 100 percent with net capacity of 25,000 Bbls/d. The increased ownership of the Joffre plant added net capacity of 125 Mmcf/d and terminalling with net capacity of 5,200 Bbls/d. AltaGas operates the Edmonton Ethane Extraction Plant, the Joffre Extraction Plant, the Bantry field facility and the Younger Extraction Plant.

Extraction Production
Bbls/d

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and pentanes plus as separate marketable commodities and their value as constituents of the natural gas stream. If the components are not extracted, they are sold as natural gas for their heating value at the prevailing natural gas price. As ethane and NGLs, the components are sold at higher prices that reflect the premium value for each of the individual commodities. In most cases the NGLs recovered at natural gas processing and extraction plants in western Canada are delivered into a system of pipelines that collects and moves NGLs to Fort Saskatchewan, Alberta or Sarnia, Ontario. NGLs are used directly as an energy source and as feedstock for the petrochemical and crude oil refining industries. NGLs, predominantly ethane, are feedstock for ethylene production.

Extraction facility owners have the right to extract liquids from the natural gas stream, either directly as the owner of the gas, or through NGL extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with shippers on a gas transmission system for the right to extract the ethane and NGLs from the shipper's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy content of the shipper's natural gas. The extraction plant owner pays the shipper for the extracted energy or alternatively purchases a sufficient volume of natural gas from the market to replace the extracted energy, thereby keeping the shipper whole. This purchased gas is referred to as shrinkage or make-up gas. Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements.

Transmission

AltaGas owns five natural gas transmission systems and one condensate pipeline. Effective with the Taylor acquisition on January 10, 2008 the transmission business includes the Ethylene Delivery System (EDS) and the Joffre Feedstock Pipeline (JFP). The EDS is used to transport ethylene, the main product produced by the NOVA Chemicals Joffre petrochemical complex, to industrial customers and storage facilities in the Edmonton and Fort Saskatchewan areas. The EDS is a 180-km, 12-inch diameter pipeline with capacity of 90,000 Bbls/d. The JFP transports NGLs from Fort Saskatchewan to the NOVA Chemicals Joffre petrochemical complex. JFP is a 180-km, 10-inch diameter pipeline with capacity of 50,000 Bbls/d.

The Suffield System in southeastern Alberta accounted for 72 percent of transmission net revenue in 2007 and has capacity of 400 Mmcf/d. The majority of the Suffield System's capacity is currently contracted by EnCana through transport-or-pay and volume commitments that will expire in 2022 and be renewable for one-year periods thereafter.

Contractual volume commitments are expected to increase annually from approximately 370,000 GJ/d in 2007 to approximately 406,000 GJ/d in 2010 and will decline thereafter.

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 39 receipt points and 36 delivery points (including four pipeline interconnects). The Kahntah pipeline transports natural gas from British Columbia to Alberta and is contracted on an annual basis. The Porcupine Hills pipeline in southwest Alberta is a single-shipper condensate pipeline. The Summerdale and Battle Lake pipelines transport natural gas in central Alberta.

Results of Operations

Financial Results ($ millions)	**2007**	**2006**
Revenue	**142.9**	149.1
Net revenue	**67.4**	63.2
Operating and administrative expense	**20.3**	20.3
Amortization expense	**8.0**	7.7
Operating income	**39.1**	35.2

Operating Statistics	**2007**	**2006**
Extraction inlet capacity (Mmcf/d) [1]	**554**	554
Extraction volumes (Bbls/d) [2]	**20,108**	19,696
Transmission volumes (Mmcf/d) [2] [3]	**407**	400
Frac spread ($/Bbl) [2] [4]	**$ 21.38**	$ 18.47

(1) As at December 31.

(2) Average for the period.

(3) Excludes condensate pipeline volumes.

(4) AltaGas reports an indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

AltaGas Extraction and Transmission Assets

As at March 3, 2008.

Operating income in the E&T segment in 2007 was $39.1 million, up from $35.2 million in 2006. The increase was primarily due to higher frac spreads and higher frac spread-exposed NGL volumes in the extraction business and the expansion of the Cold Lake transmission system.

In 2007, average ethane and NGL volumes increased primarily as a result of the increased ownership at one of the extraction plants and higher utilization. Transmission volumes also increased slightly to 407 Mmcf/d from 400 Mmcf/d primarily due to higher deliveries on the Suffield transmission system.

Net revenue was $67.4 million in 2007, compared to $63.2 million in 2006. The increase was primarily due to higher frac spreads ($1.4 million), higher extraction volumes ($1.8 million), the expansion of the Cold Lake transmission system and higher committed volumes on the Suffield system.

Operating and administrative expense in the E&T segment in 2007 was $20.3 million for 2007 and 2006. Lower costs due to lower volumes processed through the Edmonton Extraction Plant were offset by the increased costs at one of the Empress facilities due to the increased ownership.

Amortization expense in 2007 was $8.0 million compared to $7.7 million in 2006. The increase was due to the increased ownership at one of the Empress facilities and the enhanced ethane recovery project at the Edmonton extraction plant.

E&T Outlook

Results in the E&T segment are expected to increase materially in 2008. The acquisition of Taylor has added approximately 1 Bcf/d of inlet processing capacity, 23,500 Bbls/d of NGL production and 140,000 Bbls/d of NGL transportation capacity. Operating income in the E&T segment as a percentage of total operating income from all business segments is expected to increase from 25 percent in 2007 to approximately 40 percent in 2008. Volumes are also expected to increase as a result of opportunities to optimize and upgrade the infrastructure and consolidate extraction facilities in AltaGas' operating areas resulting in increased utilization and hence earnings.

Approximately 90 percent of the revenue from the E&T segment is based on long-term fee-for-service, cost-of-service and minimum volume commitment long-term contracts. The segment is expected to continue to deliver strong performance and predictable and stable returns. Commercial arrangements are structured to manage exposure to commodity price movements such that the majority of the volumes have downside protection to volatility and the remaining volumes allow AltaGas to participate in upside opportunity. These remaining volumes are driven by frac spreads which are expected to remain above recent historical levels. NGL prices continue to track the crude oil price which is expected to stay strong through 2008 while natural gas prices are expected to remain relatively flat resulting in continued strong frac spreads. Approximately 12 percent of extraction volumes are exposed to frac spread and approximately 45 percent of those volumes have been hedged at approximately $21/Bbl for 2008. The remaining volumes remain exposed to frac spread. The current forward curve for frac spread is in the low to mid-$20/Bbl range.

In second quarter 2008 a 23-day maintenance turnaround is planned at one of the facilities and is expected to cost approximately $4.0 million in direct costs and lost operating income. In third quarter 2008 there are planned turnarounds for a total of 48 days at three facilities which are expected to cost approximately $1.8 million in direct costs and lost operating income.

AltaGas has been an active participant in the Inquiry to ensure its existing and future extraction business is not negatively impacted. Proposed changes to the existing NGL extraction convention have been analyzed and mitigation strategies formulated. AltaGas believes that with the strategies in place, the outcome of the Inquiry will have no material impact on the extraction business.

On March 8, 2007, the Government of Alberta introduced legislation to reduce greenhouse gas emissions. The Climate Change and Emissions Management Amendment Act, along with its accompanying Specified Gas Emitters Regulation (SGER), state that facilities that emit more than 100,000 tonnes of greenhouse gases per year must reduce their emissions intensity by 12 percent per annum starting July 1, 2007. The Harmattan Complex falls within the scope of the legislation as its greenhouse emissions are slightly above 100,000 tonnes per year. Management's initial calculations for emissions intensity for 2007 indicate that the emissions from the Harmattan Complex are below its target intensity and therefore will not be subject to any penalty.

In the transmission business, the full year of the Cold Lake expansion is expected to increase results compared to 2007 and AltaGas expects to pursue expansions similar to the Cold Lake Expansion, which may further enhance returns in the segment. An arrangement to utilize an unused portion of the Ethylene Delivery System has been completed and is also expected to result in higher results in 2008.

Business Strategy and Opportunities

The E&T segment provides safe and reliable processing and transportation services to its customers. The strategic focus is on optimizing current infrastructure and increasing throughput and market share to improve profitability through long-term fixed-fee or cost-of-service contracts. The main business driver in the extraction business is the volume of ethane and NGLs produced which is directly correlated to the volume of natural gas processed, natural gas composition, recovery efficiency of the extraction plant, plant on-line time, contractual arrangements and commodity price.

The E&T segment's business strategy is to:

- Maximize the profitability of the existing extraction and transmission infrastructure:
  - Increase throughput and utilization of existing extraction and transmission infrastructure;
  - Recontract for services to increase returns;
  - Execute commercial arrangements that have long-term fixed-fee or cost-of-service components;
  - Use frac spread hedges to lock-in margins and reduce exposure to frac spread volatility;
  - Operate plants to mitigate downside risk when frac spreads are low;
  - Lever existing assets and services to capture accretive growth; and
  - Offer marketing, transportation management and processing services in cooperation with the Energy Services and FG&P segments.
- Grow its extraction and transmission infrastructure:
  - Acquire and develop new facilities; and
  - Increase working interest ownership of partially owned plants.

There are many opportunities to enable AltaGas to execute its strategies in the E&T segment. Extraction growth opportunities may arise from plant modifications to increase product recoveries at facilities in which AltaGas already has ownership, by increasing interests in existing extraction plants, through construction of new facilities and by increasing throughput through additional extraction agreements. Extraction plant opportunities typically reflect a long-term, cost-of-service ethane processing arrangement contracted with Alberta ethylene producers, long-term NGL fixed processing fee arrangements and a small percentage of short-term sales of NGLs based on an Edmonton or U.S. index.

The natural gas supply to the Joffre and Edmonton extraction plants depends on natural gas demand pull from central Alberta's petrochemical industry, residential and other commercial usage. The economy in the area remains strong, resulting in sustained volumes of gas processed at these plants. The Empress extraction plants rely on the supply of natural gas from natural gas export volumes, while the Younger extraction plant is supplied from the robust natural gas producing region of northeast British Columbia. Growth in NGL production at Younger will depend on the ability to increase natural gas volumes processed at the plant. The Harmattan Complex is a significant service provider in its capture area. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and optimize asset utilization and increase profitability. The Harmattan Co-Streaming Project is also expected to increase processing capability to the plant. Overall, the diverse nature of its extraction infrastructure should allow AltaGas to increase throughput, utilization and profitability.

The extraction business is also strongly influenced by frac spreads. As frac spreads are at historically high levels and are expected to remain high into the foreseeable future, AltaGas expects to show strong results from this business.

The transmission business' main value drivers are the fees earned, which are based on contracted volumes and transmission capacity to serve new and expanding customer requirements for shipping gas to market. Due to the integrated nature of AltaGas' businesses, transmission services are often offered in combination with AltaGas' gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is limited or non-existent. In capturing opportunities, AltaGas focuses on long-term, cost-of-service type contractual arrangements. Increased activity in heavy oil in the Cold Lake area is expected to provide AltaGas with additional opportunities to expand its Cold Lake system in a similar fashion to the expansion completed in 2007. Drilling activity in areas served by AltaGas' other transmission assets is also expected to provide opportunities to expand infrastructure and increase utilization of the assets.

Risk Management

AltaGas' extraction facilities and transmission assets process or transport natural gas, NGLs and condensate from the WCSB. Utilization of these facilities is dependent on a number of factors including natural gas supply, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the longer-term price of natural gas, the level of demand for ethane and NGLs and the regulatory environment for NGL market participants. The extraction business is further influenced by natural gas composition and the difference between the value of the ethane, propane, butane and pentanes plus as separate marketable commodities and their value as constituents of the natural gas stream. AltaGas manages its exposure to financial risk in the E&T segment using the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Long-term decline in throughput and gas composition variability	• Contract provisions underpin capital commitments. • Long-term contracts independent of throughput. • Collaborate with Energy Services segment to increase volumes through the extraction facilities.	• Majority of contracts are multi-year. • In 2007 75 percent of NGL production under long-term, fixed-fee arrangements. • Ethane production sold under long-term, cost-of-service or fixed-fee contracts. • Utilization at Empress facilities above 98 percent in 2007 despite a 23-day shutdown in May. • 99 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed-fee.
	• Expand existing facilities or acquire or construct new facilities.	• Expanded the Cold Lake natural gas transmission system. • Completed the Taylor acquisition and added Harmattan Complex, the Younger Plant, the remaining ownership in Joffre Extraction Plant, and two NGL pipelines.
Commodity price fluctuations	• Contracting terms and processing fees independent of commodity prices with fee-for-service or cost-of-service provisions. • Hedging practice to reduce exposure to frac spread volatility and lock-in margins when the opportunity arises to increase profitability.	• NGL is reinjected or extraction operations are reduced or suspended when uneconomical to produce. • Less than 9 percent of total extraction production was exposed to frac spreads in 2007. • Ethane production sold under long-term, cost-of-service or fixed-fee contracts. • 75 percent of NGL production under long-term, fixed-fee arrangements. • The transmission business is not directly affected by commodity price fluctuations. • Hedged 45 percent of volumes exposed to frac spread for 2008.
Increasing operating costs	• Acquire large working interests to control and optimize operations and maximize efficiencies. • Structure fees to recover actual operating costs.	• Significant portions of cost-of-service contracts provide for operating cost recovery. • Some extraction contracts allow recovery of certain operating costs, including shrinkage gas attributable to that production. • Operator of all transmission assets and four of six extraction facilities. • Maintenance management programs ensure tight cost controls and equipment reliability.
Environmental and safety	• AltaGas has strong safety and environmental management systems, which it continually strives to improve.	• Maintained its Certification of Recognition from Alberta Human Resources and Employment.
Government and regulatory changes	• Regulatory and commercial personnel work closely to monitor and react to regulatory issues.	• Active participation in industry committees and regulatory forums.

POWER GENERATION

AltaGas has 353 MW of coal-fired base-load capacity through a 50 percent ownership interest in the Sundance B PPAs and a capital lease for 25 MW of gas-fired peaking capacity. The Trust also has a 25 percent interest in a 7 MW run-of-river hydroelectric generation facility in British Columbia as a result of the Taylor acquisition. AltaGas' 378 MW of installed power capacity served approximately 5 percent of Alberta's power demand in 2007. In 2007 AltaGas also purchased 14.4 MW of gas-fired peaking capacity which is currently being installed at two FG&P locations in Alberta. The Power Generation segment is primarily engaged in the sale of electricity and ancillary services to the Alberta wholesale market.

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output. The 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to a specified target level of 86 percent of the Sundance B plants' rated capacity and to ancillary services until December 31, 2020.

175 MW
of renewable generation under development.

Results in the Power Generation segment are largely driven by generator availability, hedge prices (for the portion of capacity that is hedged) and Alberta spot prices (for the portion of capacity that is not hedged). The relationship among production, spot prices and cost of sales is specified in the PPAs. Generally, AltaGas is compensated when power production is less than target levels, at a rate based on the previous 30-day average spot price (RAPP). Similarly, if generation from the PPAs is above target, AltaGas is obligated to provide the owner of the generation facility, TransAlta Corporation (TransAlta), financial compensation based on the difference between actual availability and target availability, multiplied by the RAPP. The financial exposure may be positive or negative depending on the difference between the current Alberta spot price and RAPP. The majority of the cost of sales is the fixed costs and variable operating costs paid to TransAlta and the variable costs of transmission and Alberta Power Pool trading charges. The price for coal purchased through the PPAs is based on pre-defined formulae tied to inflation, rather than the prevailing market price for coal.

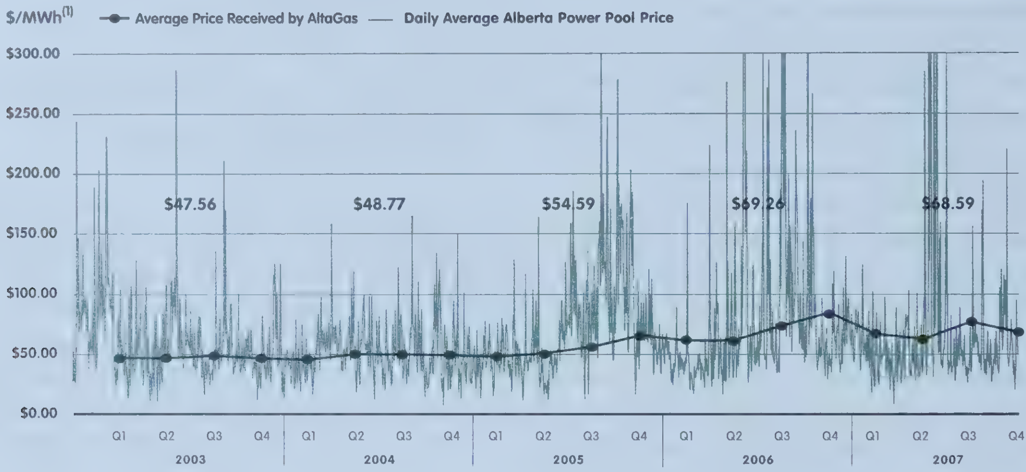
AltaGas also leases, operates and maintains 25 MW of gas fired generation. The lease began in September 2004 and includes an option at the end of the initial term of 10 years to renew for a further 15 years or to purchase the assets. The Energy Services segment manages the gas requirement and the units are dispatched from the Edmonton extraction plant. This 25 MW of gas-fired peaking capacity provides fuel diversity to AltaGas' power business and provides partial backstopping to outages at Sundance. In addition, due to their quick ramp up capability, the peaking plants provide revenue from the sale of energy and ancillary services. Construction is underway for an additional 14.4MW of gas-fired peaking capacity at the Bantry and Parkland gas processing facilities. Upon connection to the electricity grid, the new gas-fired peaking plants will increase the Trust's peaking capacity by 58 percent and further increase operational flexibility and backstopping to the Sundance B PPAs.

Results of Operations

Financial Results ($ millions)	2007	2006
Revenue	**182.5**	199.4
Net revenue	**104.2**	99.6
Operating and administrative expense	**2.1**	1.3
Amortization expense	**7.5**	7.4
Operating income	**94.6**	90.9

Operating Statistics	2007	2006
Volume of power sold (GWh)	**2,661**	2,878
Price received on the sale of power ($/MWh) (1)	**68.59**	69.26
Alberta Power Pool average spot price ($/MWh) (1)	**66.84**	80.48

(1) Average for the period.



(1) Chart truncated at $300.00; daily average Alberta power pool price reached as high as $999.99/MWh.

Operating income in the Power Generation segment was $94.6 million for 2007 compared to $90.9 million for 2006. The increase was due to higher power prices received on hedged sales, lower PPA costs and lower transmission costs. These increases were partially offset by lower revenue from unhedged sales due to lower Alberta spot power prices, the expiration of the Genesee contract and costs incurred to comply with Alberta's SGER.

The volume of power sold in 2007 was lower than in 2006 primarily as a result of the Genesee contract expiration on March 31, 2006.

Net revenue was $104.2 million for 2007 compared to $99.6 million for 2006. The increase included $34.6 million due to higher hedge prices, $9.4 million due to lower PPA costs mainly as a result of a favourable 30-day RAPP during the Sundance B planned outage and lower transmission costs of $3.2 million. These increases were partially offset by lower revenue from unhedged sales due to lower Alberta spot power prices ($35.8 million), the expiration of the Genesee contract ($4.1 million), $2.0 million of costs incurred to comply with Alberta's SGER and approximately $0.5 million in other fixed and variable costs.

Operating and administrative expense of $2.1 million in 2007 was higher than the $1.3 million reported in 2006, primarily due to the operating and maintenance services AltaGas began providing to the leased peaking plants in March 2007.

Amortization expense of $7.5 million in 2007 was similar to $7.4 million in 2006.

AltaGas Power Generation Assets

As at March 3, 2008.

Power Generation Outlook

Operating income in the Power Generation segment is expected to be higher in 2008 than in 2007. The contribution from hedged power volumes is expected to be higher than in 2007 as a result of average hedge prices of approximately $76/MWh in 2008 compared to $66/MWh in 2007. Consistent with AltaGas' hedge program, approximately two-thirds of the power available from the Sundance B PPAs has been hedged and the remaining is exposed to the spot price of power in Alberta. In early 2008, the forward market for power prices indicates that power prices will remain relatively strong, in the low to mid-$70/MWh range until 2012. PPA costs are expected to be higher in 2008 due to higher power generated. However, as the price for coal purchased through the PPAs is based on pre-defined formulae tied to inflation rather than the prevailing market price of coal, it is not expected to have a significant impact on PPA costs in 2008.

On June 27, 2007 the Alberta government passed the SGER which requires large final emitters to reduce greenhouse gas emissions intensity by 12 percent per year beginning July 1, 2007, to purchase an equivalent amount of offset credits from intra-Alberta sources, or to pay $15/tonne of emissions over the 12 percent reduction into a provincially administered technology fund. This regulation affects the Sundance facility and is expected to increase 2008 operating expense by approximately $5 million. To the extent these costs can be recovered through higher power pool prices, by the physical reduction of emissions intensity, or by creating or acquiring offsets, the impact of these costs would be mitigated.

The 14.4 MW of new gas-fired peaking capacity will be integrated into ongoing operations and is expected to be operational in second quarter 2008. Installation of the generating capacity is estimated to cost approximately $10 million and is expected to be accretive to net income and cash flow once operational.

Revenue from the gas-fired peaking facilities is derived from the sale of energy and ancillary services. Based on the expected spot price for power and natural gas in Alberta for 2008, AltaGas expects the utilization of its gas-fired peaking facilities to average 20 percent. The plants also provide ancillary services, which generate revenue without delivering power to the grid.

Business Strategy and Opportunities

The Power Generation segment consists primarily of AltaGas' 50 percent ownership of the Sundance B PPAs, which are contractual arrangements entitling the Trust to the output from the 353 MW coal-fired base-load Sundance B plant. The Trust's current hedging strategy and its gas-fired peaking plants optimize financial and operating risk related to the PPAs. The Trust's strategy is to maximize the profitability of the existing power assets and to grow its power generation infrastructure and operational capability.

AltaGas' Power Generation strategy is to:

- Maximize the profitability of the existing power assets:
  - Evaluate, modify and refine the power hedge strategies as appropriate to increase earnings stability and growth from the Sundance PPAs;
  - Dispatch the gas-fired peaking capacity in real time to maximize revenue from both energy and ancillary services;
  - Identify and execute opportunities to create value from the regulation of greenhouse gas emissions; and
  - Capitalize on internal synergies and integration efforts with other operating segments.
- Grow its power infrastructure:
  - Acquire and develop power infrastructure supported by strong power supply and demand fundamentals;
  - Acquire and develop power generation projects supported by long-term power sales arrangements;
  - Diversify power generation portfolio by geography and fuel source;
  - Develop operating capability in other fuel sources;
  - Capitalize on increasing demand for clean power by investing in renewable and clean power project development across Canada and the northern U.S.; and
  - Invest in power opportunities such as additional PPAs in Alberta and other jurisdictions.

The supply-demand fundamentals supporting the Power Generation segment remain favourable in North America. AltaGas expects this will continue to support strong power prices especially in Alberta where the Trust is most exposed to power prices. This could increase the profitability of AltaGas' power generation assets allowing AltaGas to earn higher revenues from the sale of power and ancillary services. The expectation of continued strong power prices is supported by the tightening of the electricity reserve margin in Alberta, as transmission constraints are delaying the addition of new generation facilities. In December 2007, the Alberta Electric System Operator (AESO) published a report titled "Future Demand and Energy Outlook, 2007-2027" which projected provincial demand growing at an average annual rate of 3.2 percent over the next five years. Given the demand and supply forecasts, AltaGas expects reserve margins to remain at less than 10 percent until 2011 at which time it is expected to increase to about 15 percent. In early 2008 the forward curve for power prices indicates that prices will remain relatively strong, in the low to mid-$70/MWh range until 2012. As at December 31, 2007, 93 percent of AltaGas' generation capacity was low-cost base-load coal-fired generation, resulting in strong future earnings in this market environment.

Power generation development and ownership opportunities are likely to arise as a function of the growing North American demand for cleaner energy sources such as natural gas, hydro and wind. The planned decommissioning of thermal plants in Ontario and, beginning in 2010, in Alberta, may present additional growth opportunities through the development and ownership of new capacity. In 2006 AltaGas forged relationships with power generation developers to pursue its strategy to grow its renewable energy portfolio. In 2007 the Trust acquired 100 percent of the BMWLP which owns the Bear Mountain Wind Park under construction near Dawson Creek, British Columbia. In July 2007 the GEDLP owned 50 percent by AltaGas, responded to Manitoba Hydro's 300 MW Wind Request for Proposal (RFP). While the partners were not successful in this RFP, GEDLP may bid the projects into future RFPs.

The Power Generation segment is poised for growth with the Bear Mountain Wind Park under construction and expected to be in service in November 2009. At present AltaGas owns 100 percent of the Bear Mountain Wind Park and intends to include one or more third-party investors in the project, which would reduce ownership in the wind park to approximately 45 percent. AltaGas also has several run-of-river hydroelectric projects, including two 10-MW plants with 40-year energy purchase arrangements with BC Hydro, which are currently in the permitting and licensing phase and expected to be in service in 2010. In February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric power generation in British Columbia. GEDLP has also developed a portfolio of power projects in Canada and the United States that the Trust believes will fuel further growth in its power infrastructure.

Risk Management

The main risks faced in the power business are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risk related to the deregulation of power and environmental legislation. Power results are generally driven by volumes of power generated, power prices and the cost of power. Power prices are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, economic activity and economic growth. The cost of power is driven by operating costs, changes in transmission rates, and reductions in power available for sale, mainly due to outage and force majeure events. AltaGas mitigates these risks through the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Power price volatility	• A disciplined hedging strategy – hedge targets approved by the Board of Directors. • Hedge transactions monitored by the Risk Management Committee. • In-depth Alberta power market knowledge and experience. • Hedge own electrical demand requirements. • Own and operate gas-fired peaking capacity which backstops the Sundance PPAs and sells energy and ancillary services in volatile markets.	• Financial hedge contracts generally have terms ranging from three to 36 months. • Average sales price received in 2007 was $68.59/MWh, compared to average monthly Pool price that ranged from a low of $48.37/MWh in May to a high of $155.73/MWh in July. • Supply 11 MW for own use and supply approximately 40 MW to Alberta power retail customers. • Peaking plants contributed $4.3 million to net revenue in 2007 through sales of ancillary services and energy.
Volume of power generation	• PPAs set specified target availability levels. TransAlta is obligated to provide AltaGas financial compensation to the specified target availability level which was 86 percent of rated capacity in 2007. This is accomplished by a financial payment based on the difference between actual availability and target availability, multiplied by the 30-day RAPP. • Diversification of fuel sources and geography. • Hedging strategy balances price and operating risk. • Pursue further diversification through development partnerships and acquisitions. • Reciprocal backstopping agreements with another generator to supply power at a fixed price during force majeure events.	• Minor impact on revenue during 2007 planned outage. • 25 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs. 14.4 MW additional peaking capacity under construction. • Short-term power purchase contracts used to mitigate the impact of 2007 planned outage. • Wind and hydro power projects under development outside Alberta. • Strong operating history at Sundance B with no significant loss as a result of a force majeure event.
Cost of power	• Cost of power from the coal-fired generation based on PPA indices. • Cost of power is not exposed to market price of coal.	• Modest decrease in cost of power from Sundance PPAs in 2007.
Counterparty risk	• Strong credit policies in place. • Counterparty credit reviews continually updated. • Credit thresholds established using conservative credit metrics. • Exposures and impact of price shocks on liquidity closely monitored.	• All financial hedge counterparties are investment-grade. • No counterparty defaults in 2007.
Construction risk	• Major Projects group manages and monitors significant construction projects. • Use EPC contracts where appropriate to manage construction cost risk. • Effective procurement policies and procedures and vendor selection.	• Executed EPC with Enercon for delivery and installation of the Bear Mountain Wind Park turbines.
Lack of community support	• AltaGas has active corporate and regulatory affairs departments.	• Held several events to inform and educate the communities in which AltaGas is developing projects.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Regulatory risk	• The PPAs have provisions for financial relief in the event that policies and regulations render them uneconomic.	• AltaGas personnel hold influential positions on key industry policy and oversight committees.
Environment and safety risk	• AltaGas has strong safety and environmental management systems which are continuously being monitored for improvements. • Focus on mitigating the impact of the SGER.	• Bantry and Parkland peaking plants will use compressed natural gas to drive the peaking plant starter motors. The compressed gas will then be captured and cycled through the peaking plants rather than vented into the environment. • Potentially capture offsets from existing AltaGas operating facilities. • Possible offset through higher Alberta Power Pool prices.

ENERGY SERVICES

The Energy Services segment consists of two main components: an energy management business providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users; and a gas services business which supports the operations of the FG&P, E&T and Power Generation segments and buys and resells natural gas, transportation and storage. This segment also included a small portfolio of oil and natural gas production assets that were sold in May 2007.

Energy Management

Adding value
to our infrastructure business.

The energy management business consists of providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users. As of January 1, 2007 AltaGas' energy management services are provided under the brand name "ECNG Energy" and are supported by employees in: Burlington and Chatham, Ontario; Calgary, Alberta; and Burnaby, British Columbia.

The majority of the energy management fee-for-service revenues is based on one-to-three-year evergreen contracts, with some extending as far as eight years. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply arrangements with their risk and budget objectives. The energy management business also manages electricity supplies for AltaGas' internal power demand in the FG&P and E&T segments and sells power to industrial and commercial end-users, thereby providing a longer-term market for hedging power sales.

In the energy management business, AltaGas primarily enters into agency retainer agreements with clients under which it provides gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-user customers, also purchases, manages and fixes the price of the client's natural gas and electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in the commodity prices.

Gas Services

One of the key functions of the Energy Services segment is to support AltaGas' infrastructure businesses. The gas services group contracts supply and shrinkage gas for AltaGas' extraction facilities. It also contracts and resells capacity on AltaGas transmission pipelines and provides gas control services to balance gas flows. Gas services markets gas for FG&P customers and in the process earns margins, manages credit exposure, and provides additional value-added services to AltaGas' producer customers. In addition, it contracts and manages gas for AltaGas' gas-fired power peaking plants.

In addition to supporting other operating segments within AltaGas, the gas services business identifies opportunities to buy and resell natural gas, market natural gas for producers and exchange, reallocate or resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems and differences in natural gas prices from one period to another. Fixed margins are earned by simultaneously locking in buy and sell transactions and managing potential credit exposures. AltaGas also provides energy procurement services for large industrial and utility gas users, and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' gas services business also includes transportation arrangements into the eastern Canadian markets and within Alberta in the form of gas exchange arrangements with AltaGas' gathering and processing customers. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has been successful in achieving positive margins while providing improved netbacks for producers.

Over the past several years, AltaGas had accumulated a portfolio of oil and natural gas production assets in connection with larger acquisitions of gathering and processing facilities. These oil and natural gas assets were sold in the second quarter of 2007.

Results of Operations

Financial Results ($ millions)	2007	2006
Revenue	**1,022.5**	948.9
Net revenue	**20.9**	24.7
Operating and administrative expense	**15.6**	17.1
Amortization expense	**3.3**	4.8
Operating income	**2.0**	2.8

Operating Statistics	2007	2006
Energy management service contracts (1)	**1,466**	1,394
Average wholesale volumes marketed (GJ/d) (2)	**388,217**	327,057

(1) Active energy management service contracts at the end of the reporting period.

(2) Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

Operating income in the Energy Services segment was $2.0 million in 2007 compared to $2.8 million in 2006. The decrease was due to non-recurring earnings reported in the energy management business in 2006, higher gas costs to supply a natural gas contract, higher operating and administrative expense and lower contributions from the operations of the oil and natural gas production assets which were sold effective May 31, 2007. These decreases were partially offset by an increased fixed-price commodity and transportation net revenue in the gas services business, growth in both gas and electricity in the energy management business and the one-time pre-tax gain from the sale of the oil and natural gas production assets.

Net revenue was $20.9 million in 2007 compared to $24.7 million in 2006. The decrease included a $4.0 million lower contribution due to lower volumes and prices related to the operation of the oil and gas production assets, $2.5 million related to non-recurring earnings in the energy management business, and $1.4 million due to higher gas costs to supply a natural gas contract. These decreases were partially offset by $2.0 million from higher optimization, transportation, fixed-price and balancing gas margins in the gas services business, the one-time pre-tax gain from the sale of oil and natural gas production assets of $1.5 million and $0.5 million from growth in the energy management business.

Operating and administrative expense was $15.6 million in 2007 compared to $17.1 million in 2006. The decrease was primarily due to lower costs related to the operation of the oil and natural gas production assets ($2.0 million), partially offset by $0.5 million in higher administrative expenses.

Amortization expense in 2007 was $3.3 million compared to $4.8 million in 2006. The decrease was primarily due to the sale of the oil and natural gas production assets of $1.7 million, partially offset by higher amortization of $0.2 million related to the addition of new information systems to support the business.

Energy Services Outlook

The increased gas infrastructure acquired through the Taylor transaction is expected to provide additional opportunities for the Energy Services business to identify and execute on opportunities to enhance the earnings from these assets. To the extent that the Energy Services segment can do so, this may increase earnings in the segment or contribute to increased earnings in the other operating segments.

The core businesses within the Energy Services segment are the advisory fee-based business servicing non-residential gas and electricity end-users (energy management), and the fixed-margin gas marketing business (gas services). AltaGas expects results in the Energy Services segment in 2008 to be slightly lower than 2007 results, excluding the gain on sale of the oil and gas production assets in 2007. Lower revenues from fixed-price gas sales are anticipated due to the low natural gas price environment. However, the recent acquisition of Taylor will provide the gas services business with an increased geographic footprint and assets to increase its integration opportunities to enhance unitholder value.

The Energy Services segment is an important element in increasing the value of assets in AltaGas' other segments. Energy Services works with the other segments to optimize AltaGas' assets and in this capacity is expected to contribute to earnings growth across all segments.

Business Strategy and Opportunities

The Energy Services segment provides agency advisory services to energy end users in the commercial, institutional, small industrial and agricultural sectors and locks in margin through the buying and selling of natural gas, transportation and storage. The segment also provides value added services to the FG&P, E&T and Power Generation segments and their customers by capitalizing on its in depth knowledge of the energy markets to optimize AltaGas' infrastructure and enhance value.

AltaGas' Energy Services business strategy is to:

- Maximize profitability of its existing business:
    - Identify opportunities for increased synergies and value across AltaGas' infrastructure and services to increase profitability;
    - Create new service offerings and build on national brand development;
    - Increase market penetration of national energy management services in natural gas and electricity;
    - Manage credit and market risk within the risk tolerances established by the Board; and
    - Increase cost efficiency and improve competitive advantage through common processes and marketing efforts.
- Grow Energy Services infrastructure:
    - Add physical infrastructure such as gas storage capacity.

The key value driver in the Energy Services segment is the services provided to the other infrastructure based business segments. The Energy Services segment provides gas control and gas supply contracting services to the FG&P, E&T and Power Generation segments. AltaGas' strategy is to identify additional opportunities to enhance the value of its infrastructure through transactions and support services. This includes identifying opportunities to increase margins earned in transmission, maintain the cost-effective flow of gas through extraction plants and increase services provided to producers.

The Energy Services business provides AltaGas with a portfolio of contracts with locked-in margins over multiple years. These contracts result in stable and predictable earnings and cash flows. However, these transactions require credit support to backstop potential default risk with suppliers and customers. AltaGas allocates capital to this business based on the credit risk profile of the contracts in order to avoid excessive exposure to default risk. The Trust closely monitors the credit and market risk profile of the contracts through metrics such as value at risk and credit event liquidity analysis.

The Energy Services business incurs significant general and administrative (G&A) expenses as it employs high human capital. AltaGas is focused on operating margin as a percentage of G&A and strives to increase this metric through cost efficiencies from common processes, marketing efforts and promotional materials. Sharing of gas and electricity market knowledge across all regions and streamlining the operations to more effectively serve customers across Canada is also expected to result in improved margins.

In 2007 AltaGas announced its first infrastructure project in the Energy Services segment with the development of the Sarnia Airport Storage Pool project in Ontario. This is AltaGas' first investment in storage infrastructure and is expected to be in service in 2009. Access to a storage asset near the Dawn Hub in Ontario is expected to provide AltaGas with the ability to further capitalize on its in-depth knowledge of the eastern gas markets to further enhance unitholder value. Given the long-term supply and demand fundamentals of natural gas and the increasing impact of liquefied natural gas in the North American natural gas markets, storage capacity is expected to play a more strategic role in the buying, selling and transportation of gas. AltaGas expects to pursue further growth opportunities in storage infrastructure to further enhance margins in Energy Services.

Risk Management

In the energy management business, AltaGas competes with other marketing and consulting firms. In the gas services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies. The primary source of competition is the marketing arms of large oil and gas producers. The most significant risks in the Energy Services segment are counterparty and commodity price risk. The credit-intensive nature of this business requires balance sheet support to transact fixed-price energy supply purchase and sale agreements.

While long-term fixed-margin contracts provide stable earnings and cash flow, the Trust employs a disciplined approach to credit allocation to mitigate the risk of counterparty default. AltaGas mitigates these risks through the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Counterparty default	• Strong credit policies in place. • Internal credit ratings and thresholds established. • Exposures and impact of price shocks on liquidity are closely monitored. • Diverse customer and supplier base. • Business model in energy management is based on agency arrangements where counterparty credit risk for commodity exists between the supplier and the end-user.	• Majority of counterparties are investment-grade. • In energy management business, customers are aggregated into groups with joint and several liability for payment of fees. • No Energy Services customer represented more than 8 percent of consolidated revenues during 2007. • In 2007 AltaGas added customers in key sectors nationwide. • Purchase natural gas from a wide array of investment-grade suppliers.
Commodity price fluctuation	• Commodity Risk Policy prohibits transactions for speculative purposes. • Strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy. • In-depth knowledge of transportation systems and natural gas markets. • Strong customer relationships.	• All gas service transactions are back-to-back with locked-in margins. • Energy management contracts have terms from one to eight years with locked-in fees. • Advisory fee services business experienced renewal rate of 95 percent in 2007. • Market and manage FG&P customers' gas for a fee. • In majority of energy management business AltaGas acts as agent, taking no direct commodity price risk.

CORPORATE

The Corporate segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity, return on capital and operating income as a percentage of net revenue without the impact of the volatility in commodity prices and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity as risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting on net income is reported and monitored in the Corporate segment.

Financial Results ($ millions)	2007	2006
Revenue [1]	**5.1**	4.4
Net revenue	**6.2**	4.4
Operating and administrative expense	**31.2**	29.7
Amortization expense	**2.3**	2.3
Operating loss	**(27.3)**	(27.6)
Operating loss before unrealized gains on risk management	**(28.4)**	(27.6)

(1) Excludes unrealized gains (losses) on risk management.

The operating loss before unrealized gains on risk management was $28.4 million in 2007 compared to $27.6 million in 2006. The increased loss was due to $1.3 million in higher office, computer and compensation costs and $1.9 million in write-offs related to costs incurred on development projects. These increases were partially offset by $1.0 million in lower professional and consulting fees, $0.8 million in higher general and administrative costs allocated to the operating segments and a one-time gain of $0.4 million on the unwinding of interest rate swaps as a result of the issuance of $100 million of medium-term notes in January 2007. Effective in second quarter 2007 AltaGas reduced its influence over Taylor and commenced accounting for its interest in Taylor using the cost method. The effect of the change in the accounting method on the operating loss in 2007 was negligible.

Net revenue was $6.2 million in 2007 compared to $4.4 million in 2006. The increase was due to the unrealized gain of $1.1 million related to risk management contracts and back-to-back commodity purchases and sales as a result of the adoption of accounting standards effective January 1, 2007, that require the fair value of all financial instruments to be reflected on the financial statements. On adoption, AltaGas recorded financial statement related assets and liabilities of $107.8 million and $110.6 million respectively. The net impact to accumulated earnings and to Other Comprehensive Income on January 1, 2007 was $0.2 million and $2.6 million respectively. The increase was also due to the gain recorded as a result of unwinding interest rate swaps in first quarter 2007 of $0.4 million and to $0.3 million from higher interest and investment revenue.

Operating and administrative expense was $31.2 million in 2007 compared to $29.7 million in 2006. The increase was primarily related to $1.9 million in a one-time charge related to the write-off of costs incurred on development projects and $0.4 million in higher compensation costs, partially offset by lower professional and consulting fees of $1.0 million and lower general corporate overhead.

Amortization expense for 2007 was consistent with 2006.

Corporate Outlook

The operating loss for 2008 is expected to be higher than in 2007 due primarily to the acquisition of Taylor and AltaGas growth through acquisitions and the expansion of current facilities. In 2007 Taylor recorded approximately $8 million in corporate costs on a normalized basis. AltaGas has realized approximately $2 million in cost savings of the total $3.0 million identified at the time the Taylor transaction was announced. The segment's revenue will decrease as AltaGas will no longer be recording investment income from Taylor in the Corporate segment and also due to a decrease in ownership of Utility Group from 26.7 percent to 19.6 percent.

The effects of financial instruments are based on estimates relating to commodity prices and foreign exchange rates over time. The actual amounts will vary based on these drivers and management is therefore unable to predict the impact of financial instruments. However, the impact of the accounting standards is expected to be relatively low as the Trust uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked-in margins. The Trust does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During 2007 AltaGas acquired $86.1 million in capital assets, long-term investments and other assets, up from $71.5 million in 2006. The increase was due to acquiring $68.2 million in capital assets and $17.9 million in long-term investments and other assets, of which $20.3 million was an increase in the fair value of Taylor units which were reported as assets available for sale and $3.4 million was for costs related to the acquisition of Taylor, partially offset by the special distribution of Utility Group common shares valued at $4.2 million and the elimination of $2.1 million in loans advanced to BMWLP. The $46.4 million in disposals of capital assets included the $30.2 million disposition of the original cost of the oil and natural gas production assets in Energy Services and the original cost of the $14.4 million interest in the Ikhil Joint Venture reported in the FG&P segment.

Maintenance capital expenditures totalled $5.7 million in 2007 compared to $6.1 million in 2006, of which $4.0 million in 2007 was in the FG&P segment. Of the $56.2 million spent on growth capital in 2007 (2006 – $62.0 million), $23.3 million was spent in the FG&P segment, which included $16.5 million on CBM projects consisting of the Acme plant construction and the Corbett Creek acquisition, and another $6.5 million spent on upgrading and expanding existing FG&P facilities. In the Power Generation segment, $13.9 million was spent on the Bear Mountain Wind project and $6.6 million was for the new peaking generation equipment and installation costs to date. AltaGas also invested $8.0 million in the Sarnia Airport Storage Pool project in Ontario as part of its strategy to grow its gas infrastructure and diversify geographically. Costs of $3.4 million were incurred related to the offer to purchase the outstanding Taylor units, which was more than offset by the $4.2 million special distribution of Utility Group shares to AltaGas unitholders. Administrative capital expenditures of $24.2 million in 2007 were significantly higher than the $3.4 million reported in 2006, primarily due to a $20.3 million increase in the fair value of Taylor units which were reported as assets available for sale.

For the year ended December 31, 2007 ($ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Capital assets	29.1	5.0	22.0	9.8	2.3	68.2
Long-term investments and other assets	–	–	(0.5)	–	18.4	17.9
	29.1	5.0	21.5	9.8	20.7	86.1
Disposals						
Capital assets	(15.9)	(0.3)	–	(30.2)	–	(46.4)
Net invested capital	13.2	4.7	21.5	(20.4)	20.7	39.7

For the year ended December 31, 2007 ($ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Maintenance	4.0	1.7	–	–	–	5.7
Growth	23.3	3.3	21.5	9.3	(1.2)	56.2
Administrative	1.8	–	–	0.5	21.9	24.2
	29.1	5.0	21.5	9.8	20.7	86.1
Disposals	(15.9)	(0.3)	–	(30.2)	–	(46.4)
Net invested capital	13.2	4.7	21.5	(20.4)	20.7	39.7

For the year ended December 31, 2006 ($ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Capital assets	58.5	4.3	–	0.8	2.2	65.8
Long-term investments and other assets	–	–	4.3	–	1.4	5.7
	58.5	4.3	4.3	0.8	3.6	71.5
Disposals						
Capital assets	(0.8)	–	–	–	–	(0.8)
Net invested capital	57.7	4.3	4.3	0.8	3.6	70.7

For the year ended December 31, 2006 ($ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Maintenance	5.0	0.8	–	0.3	–	6.1
Growth	53.3	3.4	4.3	0.2	0.8	62.0
Administrative	0.2	0.1	–	0.3	2.8	3.4
	58.5	4.3	4.3	0.8	3.6	71.5
Disposals	(0.8)	–	–	–	–	(0.8)
Net invested capital	57.7	4.3	4.3	0.8	3.6	70.7

FINANCIAL INSTRUMENTS

The Trust is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates, particularly in the Power Generation segment and with respect to interest rates on debt. During 2007, the Trust had positions in the following types of derivatives:

Commodity Forward Contracts

The Trust executes gas, power, and other commodity forward contracts to manage its asset portfolio and lock in margin from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The Energy Services segment transacts primarily on this basis.

Commodity Swap Contracts

The Trust executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power Generation segment's results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing the Trust's exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and whereas prices ranged from \$0.00/MWh to \$999.99/MWh in 2007, the average spot price was \$66.84/MWh for the year. AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio that management deemed optimal. The average price received for power by the Trust was \$68.59/MWh in 2007. The Trust opportunistically executes fixed-for-floating frac spread swaps to manage its NGL frac spreads.

NGL Frac Spread Hedges

The Trust executes fixed-for-floating frac spread swaps to manage its NGL frac spreads. The E&T segment's results are affected by frac spreads. In the fourth quarter of 2007, the Trust entered into NGL frac spread agreements for 1,400 Bbls/d at $25.50/Bbl for the first quarter 2008 and for 700 Bbls/d at $21.50/Bbl from April 1 to December 31, 2008. With the acquisition of Taylor, AltaGas has assumed frac spread hedges for an additional 1,200 Bbls/d with an average price of $20.00/Bbl for January 1 through December 31, 2008.

Interest Rate Forward Contracts

The Trust enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2007 the Trust had interest rate swaps with varying terms to maturity of $25.0 million. Including AltaGas' MTNs and capital leases, the rate was fixed on 100 percent of AltaGas' debt.

Foreign Exchange Forward Contracts

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts where a fixed rate is locked in against a floating rate. The Trust's foreign exchange risk was not material at December 31, 2007. The Trust has entered into a number of forward rate contracts to hedge its euro exposure as it relates to the Bear Mountain project.

LIQUIDITY AND CAPITAL RESOURCES

AltaGas expects that funds from operations in 2008 will be sufficient to meet the Trust's distributions to unitholders and the majority of its budgeted maintenance and growth capital expenditures. The balance of its budgeted growth capital and a certain amount of unbudgeted acquisitions will be financed through the Distribution Reinvestment Plan (DRIP) and existing bank lines. Should larger acquisitions require financing beyond existing sources, management is confident, based on historical success, that equity and debt capital markets could be accessed to provide additional financing. At this time AltaGas does not reasonably expect any presently known trend or uncertainty to affect the Trust's ability to access its historical sources of cash, except that cash from operations may be impacted by the taxable component of the Trust's distribution beginning in the 2011 taxation year.

On January 10, 2008 AltaGas acquired Taylor units for the aggregate purchase price of $598.7 million, including cash of $256.3 million and 7.7 million Trust units (including 0.2 million exchangeable units) valued at $198.9 million for all of the outstanding units not previously owned by AltaGas, assumed debt of $132.5 million and approximately $11.0 million in transaction costs which was funded with bankers' acceptances through AltaGas' syndicated credit facilities.

Cash Flows ($ millions)	2007	2006
Cash from operations	**183.3**	146.9
Investing activities	**(63.4)**	(78.5)
Financing activities	**(120.6)**	(66.9)
	(0.7)	1.5

Cash from Operations

Cash from operating activities reported on the Consolidated Statements of Cash Flows increased by $36.4 million, or 25 percent, to $183.3 million in 2007 from $146.9 million in 2006. The increase in cash flow was primarily due to a decrease in non-cash working capital items. Accounts receivable decreased as a result of lower volumes and commodity prices, the timing of payments in the Power Generation segment, and gas storage positions that had built up in the latter half of 2006 decreasing in 2007. The decrease in working capital was partially offset by lower payables as a result of lower commodity prices and the timing of payment of capital costs.

Working Capital ($ millions except ratio amounts)	2007	2006
Current assets	**305.4**	263.4
Current liabilities	**286.1**	239.7
Working capital	**19.3**	23.7
Current ratio	**1.07**	1.10

Investing Activities

During 2007 the Trust used cash for investing activities of $63.4 million compared to $78.5 million in 2006. The decrease in cash used for investing activities was due to lower acquisitions of capital assets in 2007, increased customer deposits and higher proceeds on dispositions of non-core assets.

Financing Activities

Cash used for financing activities was $120.6 million in 2007 compared to $66.9 million used in 2006. Significant financing activities in 2007 included a reduction to debt of $44.4 million, $8.1 million higher distributions paid to unitholders than in 2006 and $4.8 million lower proceeds from the DRIP as a result of the suspension of the Premium component of the DRIP.

Capital Resources

Debt as a Percent of Total Capitalization

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments. At December 31, 2007 AltaGas had total debt outstanding of $220.7 million, down from $265.5 million as at December 31, 2006. As of December 31, 2007 the Trust had $200.0 million in MTNs outstanding and had access to prime loans, bankers' acceptances and letters of credit through bank lines totaling $425.0 million. As at December 31, 2007 the Trust had drawn bank debt of $10.0 million and letters of credit outstanding of $64.5 million.

All of the borrowing facilities have financial tests and other covenants customary for these types of facilities, which must be met at each quarter-end. AltaGas has been in compliance with these covenants each quarter since the issuance of the facilities.

AltaGas' target debt-to-total-capitalization ratio is 40 to 45 percent. The Trust's debt-to-total-capitalization ratio as at December 31, 2007 was 27.4 percent, down from 33.4 percent at December 31, 2006. The Trust's earnings interest coverage for the rolling 12 months ended December 31, 2007 was 10.65.

The Dominion Bond Rating Service (DBRS) rates AltaGas Income Trust and the MTNs issued by AltaGas Income Trust at BBB (low). In January 2008, DBRS confirmed AltaGas' medium-term notes and stability ratings at BBB (low) and STA-3 (middle) respectively. The trend on the medium-term notes rating was changed to Stable from Positive.

Standard & Poor's Ratings Services (S&P) rates the Trust's long-term corporate credit at BBB- with a stable outlook, and the senior unsecured debt at BBB-. In December 2007 S&P affirmed AltaGas' ratings.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity of an entity to meet its financial commitment in accordance with the terms of an obligation. Stability ratings are intended to convey the opinion of a rating agency in respect of the relative stability and sustainability of an entity's distribution stream when compared to other stability rated entities.

Credit Facilities ($ millions)	Borrowing capacity	Drawn at December 31, 2007	Drawn at December 31, 2006
Demand operating facility	50.0	**2.8**	–
Letter of credit facility	75.0	**61.7**	63.3
Syndicated operating credit facility [1]	300.0	**10.0**	154.3
	425.0	**74.5**	217.6

(1) Extendible revolving-term credit facility that can be extended beyond the current term date of September 30, 2010 for an additional year.

At December 31, 2007 the Trust held a $75.0 million (2006 – $75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2007 the Trust had letters of credit of $61.7 million (2006 – $63.3 million) outstanding against the extendible revolving-term letter of credit facility and letters of credit of $2.8 million (2006 – $3.0 million) outstanding against the demand operating facility.

Contractual Obligations

	Payments Due by Period				
($ millions)	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Long-term debt	211.7	4.7	207.0	–	–
Capital leases	12.5	1.9	3.8	3.8	3.0
Operating leases	15.9	3.9	6.8	5.2	–
Purchase commitments	150.2	34.4	115.8	–	–
Total contractual obligations	390.3	44.9	333.4	9.0	3.0

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2007 was $10.0 million (2006 – $11.8 million) with the balance due in monthly payments comprising principal and interest of $0.2 million.

The Trust has long-term operating lease agreements for office space, office equipment and automotive equipment. The Trust also has purchase commitments for the development of the Bear Mountain Wind project including the purchase and installation of the wind turbines.

Other Commitments

Under the terms of a 1997 long-term gas supply contract the Trust is committed to supplying natural gas at prices ranging from $2.34/Mcf in 2007 to $2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. One of those producers defaulted on its obligation under its gas supply contract in 1999, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed-price contract with a third-party supplier to fix the price of the gas supply related to the commitment until its expiry in 2009.

DISTRIBUTIONS

AltaGas' distributions are determined giving consideration to the ongoing sustainable distributable cash flow as impacted by the consolidated net income, maintenance and growth capital and debt repayment requirements of the Trust. AltaGas declared $118.6 million of distributions to unitholders in 2007 compared to $110.8 million in 2006.

The Trust suspended the Premium component of the DRIP (PDRIP) effective with the August 2007 distribution. The regular component of the DRIP remains in effect and will continue to support AltaGas' financing strategy. In the future, as conditions warrant, the Trust may consider reinstating the PDRIP based on AltaGas' capital requirements and desire to maintain an efficient capital structure. While the PDRIP is suspended, PDRIP participants will continue to receive regular cash distributions. For further information on the DRIP please visit AltaGas' website at www.altagas.ca.

Cash Dividends/Distributions Declared per Unit
$

The Board of Directors of AltaGas General Partner Inc., delegate of the Trustee, increased its monthly cash distribution to $0.175 per unit ($2.10 per unit annualized) from $0.17 per unit ($2.04 per unit annualized) payable on September 17, 2007 to unitholders of record on August 27, 2007. This was AltaGas' fourth distribution increase since converting to a trust in May 2004. AltaGas pays cash distributions on the 15th day of each month to unitholders of record on the 25th day of the previous month or, in each case, the following business day if the payment date or record date falls on a weekend or holiday.

In addition, a special distribution of one Utility Group common share for every 100 trust units and exchangeable units of AltaGas held on August 27, 2007 was made on September 17, 2007. The Trust distributed 577,416 shares valued at $4.2 million.

The following table summarizes AltaGas' distribution declaration history since 2005:

($ per unit)		**2007**		2006		2005
First quarter	**$**	**0.510**	$	0.485	$	0.45
Second quarter		**0.510**		0.495		0.45
Third quarter		**0.520**		0.505		0.47
Fourth quarter		**0.525**		0.510		0.48
Distribution of shares [1]		**0.076**		–		0.54
	$	**2.141**	$	1.995	$	2.39

[1] On September 17, 2007, one share of Utility Group was issued for every 100 trust and exchangeable units held on August 27, 2007. On November 17, 2005, one share of Utility Group was issued for every 13.9592 trust and exchangeable units held on November 14, 2005.

Assuming a unit was held throughout 2007, for income tax purposes the Trust expects 69.73 percent of the total distributions declared in 2007 to be taxed as property income, 0.22 percent as dividend income, 0.62 percent as capital gains and 29.43 percent as return of capital. For most unitholders, the return of capital amount will reduce the cost base of their Trust units for purposes of calculating the capital gains amount upon disposition of their units. Unitholders should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

TRUST UNIT INFORMATION

Under the terms of the restructuring of AltaGas into an income trust effective May 1, 2004, ASI security holders exchanged their shares in ASI for Trust units and eligible security holders also received exchangeable units that are exchangeable into Trust units on a one-for-one basis. The exchangeable units are not listed for trading on an exchange.

Units Outstanding

At January 31, 2008 the Trust had 63.4 million Trust units and 2.2 million exchangeable units outstanding and a market capitalization of $1.5 billion based on a closing trading price on January 31, 2008 of $23.35 per Trust unit. At January 31, 2008 there were 1.3 million options outstanding and 350,967 options exercisable under the terms of the unit option plan.

CHANGES IN ACCOUNTING POLICIES

2007 Changes

Effective January 1, 2007 AltaGas adopted the revised Canadian Institute of Chartered Accountants (CICA) Handbook Section 1506. This section prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. The adoption of this standard did not have a material impact on the Consolidated Financial Statements.

Financial Instruments

Effective January 1, 2007 the Trust prospectively adopted the CICA Handbook; Section 1530 "Comprehensive Income"; Section 3855 "Financial Instruments – Recognition and Measurement"; Section 3865 "Hedges"; and Section 3861 "Financial Instruments – Disclosure and Presentation". The impacts of adopting the new standards are reflected in the Trust's annual results, and prior year comparative financial statements have not been restated. While the new rules resulted in changes to how the Trust accounts for its financial instruments, there were no material impacts on the Trust's current financial results. For a description of the new accounting rules and the impact on the Trust's financial statements of adopting such rules, see note 12 to the annual Consolidated Financial Statements for the year ended December 31, 2007.

Future Accounting Changes

Section 1535 "Capital Disclosures"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

Section 3031 "Inventories"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" provides guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. This new section is effective for the Trust beginning January 1, 2008.

Section 3862 "Financial Instruments – Disclosures" and Section 3863 – "Financial Instruments – Presentation"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

International Financial Reporting Standards (IFRS)

In 2006 the Accounting Standards Board (AcSB) published a new strategic plan that will significantly affect financial reporting requirements in Canada. The AcSB strategic plan outlines the convergence of Canadian generally accepted accounting principles with IFRS over an expected five-year transition period, with adoption required effective January 1, 2011. While AltaGas has begun assessing the adoption of IFRS for 2011, the financial impact of the transition to IFRS cannot be reasonably estimated at this time.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Trust's Consolidated Financial Statements requires the use of estimates and assumptions which have been made using careful judgment. AltaGas' significant accounting policies are contained in the Notes to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to be amortization expense, asset retirement obligations and asset impairment assessment. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustment to the amount of amortization that the Trust recognizes from period to period.

Asset Retirement Obligations and Other Environmental Costs

The Trust records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs is a critical accounting estimate because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2025 and 2035), requiring the Trust to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on the Trust's Consolidated Financial Statements.

Asset Impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing an impairment may be material to the Trust's Consolidated Financial Statements.

With respect to impairment assessment, management has made fair-value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistent with prior periods.

OFF-BALANCE-SHEET ARRANGEMENTS

The Trust is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guaranteed contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. The Trust has no obligation under derivative instruments, or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services with the Trust.

RELATED PARTIES

The Trust sold $83.4 million of natural gas to, and incurred transportation costs of $0.5 million charged by Utility Group in 2007. The Trust also paid management fees of $0.4 million to, and received management fees of $29,000 from, Utility Group for administrative services in 2007. In addition, the Trust provided $0.3 million of operating services to Utility Group.

During 2007 the Trust sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for $9.0 million. The gain on the sale was negligible.

The Trust pays rent under a lease for office space to 2013761 Ontario Inc., which is owned by an employee. Payments of approximately $85,000 were made in 2007 (2006 – $80,000). The five-year lease expired in 2007 and was renewed for an additional year.

DISCLOSURE CONTROLS AND PROCEDURES

The Trust maintains disclosure controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under applicable laws is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

In accordance with Multilateral Instrument 52-109 (Certification of Disclosure in Issuers' Annual and Interim Filings), management carried out an evaluation, under the supervision and with the participation of management, including the Chairman and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that disclosure controls and procedures were effective as of December 31, 2007 to provide reasonable assurance that information required to be disclosed is recorded, processed, summarized, and reported within the time periods specified in the Ontario Securities Commission's rules and forms.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management of the Trust is responsible for establishing and maintaining adequate internal controls over financial reporting. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be designed effectively can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Trust has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework to evaluate the design of internal controls over financial reporting.

At December 31, 2007 management assessed the design of the Trust's internal control over financial reporting and concluded that such internal control over financial reporting is suitably designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. The assessment also concluded that there were no material weaknesses in the design of AltaGas' internal control financial reporting that have been identified by management.

There have been no changes in design of internal control over financial reporting during the year ended December 31, 2007 that have materially affected or are reasonably likely to materially affect AltaGas' internal control over financial reporting.

SUBSEQUENT EVENTS

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 acquired all of the outstanding limited partnership units of Taylor NGL Limited Partnership (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of natural gas liquids extraction plants, natural gas processing assets and two natural gas liquids pipelines. It also had an interest in a 7 MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders $11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of $245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, $27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. The aggregate purchase price was $598.7 million, including $256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at $198.9 million for all the outstanding units not previously owned by AltaGas, assumed debt of $132.5 million and approximately $11.0 million in transactions costs. The value of the Trust units issued was determined based on the weighted average market price from two days preceding to two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

Total consideration for 100% of Taylor:

($ millions)		
Cost of 8.9% investment in Taylor originally owned by AltaGas		24.6
Purchase price for the remaining 91.1% of Taylor Units		
Cash considerations	256.3	
Units	198.9	
Estimated transaction costs	11.0	
Equity portion of Taylor convertible debentures	2.1	468.3
Total consideration		$ 492.9

Purchase price allocation for 100% of Taylor:

($ millions)		
Assets acquired		
Current assets	30.8	
Capital assets	590.0	
Energy service arrangements, contracts and relationships	83.9	
Goodwill	108.2	
Long-term investments and other assets	4.6	817.5
Less Liabilities assumed		
Current liabilities	31.2	
Long-term debt	110.2	
Convertible debentures	22.2	
Asset retirement obligations	14.4	
Future income taxes	144.0	
Future employee obligations	2.5	
Risk management	0.1	324.6
		$ 492.9

Until the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in Other comprehensive income. As of January 10, 2008, Taylor will be included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of $256.3 million for the Taylor acquisition. As of January 10, 2008, AltaGas had total debt of approximately $610 million compared to $220.7 million as at December 31, 2007 and a debt-to-total capitalization ratio of approximately 45 percent.

Acquisition of Potential Hydroelectric Projects

On February 13, 2008 AltaGas acquired four potential run-of-river hydro projects ranging from 6.5 to 24 MW for $4.5 million. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia. In exchange for the development assets, AltaGas issued 180,433 special warrants for AltaGas trust units valued at $24.94 per special warrant to Plutonic Power Corporation. The special warrants automatically convert to AltaGas units on a one-for-one basis on January 1, 2010.

FOURTH QUARTER HIGHLIGHTS

Net income for the three months ended December 31, 2007 was $31.8 million ($0.55 per unit) compared to $27.3 million ($0.49 per unit) for the same period in 2006. Excluding a $6.1 million non-cash tax recovery due to reduced federal tax rates enacted in fourth quarter 2007, net income for fourth quarter 2007 was $25.7 million. Net income increased primarily due to higher hedge prices and lower costs in the Power Generation segment, lower operating and administrative costs, higher frac spreads and higher extraction volumes exposed to frac spreads. These increases were more than offset by lower throughput and operating cost recoveries in FG&P, lower Alberta spot power prices and a lower contribution from the Energy Services segment.

On a consolidated basis, net revenue for the quarter ended December 31, 2007 was $76.4 million compared to $84.6 million in the same quarter of 2006. Net revenue decreased in fourth quarter 2007 due to lower Alberta spot power prices, lower throughput in FG&P, and lower revenues as a result of the sale of oil and gas production assets in May 2007. The decreases were partially offset by higher hedge prices and lower costs in the Power Generation segment, higher frac spreads and higher frac spread-exposed extraction volumes.

Operating and administrative expense for fourth quarter 2007 was $36.2 million down from $40.1 million in the same quarter of 2006. The decrease was primarily due to lower operating costs in FG&P, lower costs as a result of the sale of the Ikhil Joint Venture and the oil and natural gas production assets, as well as lower consulting fees in part related to the compliance with securities regulations incurred in 2006. These decreases were partially offset by higher compensation and administrative costs.

Amortization expense for fourth quarter 2007 was $11.4 million compared to $12.5 million in the same quarter last year. The decrease was due to the disposition of oil and natural gas production assets in 2007 and a $0.6 million write-down of goodwill on a non-core investment in fourth quarter 2006, partially offset by new and expanded FG&P facilities.

Interest expense for fourth quarter 2007 was $2.9 million compared to $3.3 million in the same quarter of 2006. The decrease was due to lower average debt balances of $218.6 million compared to $271.9 million for the same period in 2006, partially offset by higher average borrowing rates. The average borrowing rate in fourth quarter 2007 was 5.5 percent compared to 4.9 percent in fourth quarter 2006.

In fourth quarter 2007 the Trust reported an income tax recovery of $5.8 million compared an income tax expense of $1.4 million in the same quarter last year. Lower federal corporate income tax rates enacted in the quarter resulted in a tax recovery of $6.1 million and was offset by higher tax expense of $0.3 million due to higher income subject to tax.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2008 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per unit
Gathering and processing volumes [1]	5 Mmcf/d	0.016
Gathering and processing operating margin per Mcf [1]	1 cent /Mcf	0.027
Alberta electricity prices [1] [2]	$1/MWh	0.010
Natural gas liquids fractionation spread [1] [3]	$1 per Bbl	0.011
Interest rates [1]	25 bps	0.004

(1) Includes the effects of the Taylor assets added January 10, 2008.

(2) Based on 70 percent of PPA volumes being hedged.

(3) Based on 55 percent of exposed volumes not hedged.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENTLY COMPLETED QUARTERS

($ millions)	Q4-07	Q3-07	Q2-07	Q1-07	Q4-06	Q3-06	Q2-06	Q1-06
Net revenue [1]	**76.4**	88.2	80.1	79.3	84.6	82.5	72.8	79.1
Operating income [1]	**28.9**	37.5	31.2	29.0	32.0	33.7	26.0	35.0
Net income	**31.8**	31.4	21.1	24.6	27.3	28.8	29.9	28.6

($ per unit)	Q4-07	Q3-07	Q2-07	Q1-07	Q4-06	Q3-06	Q2-06	Q1-06
Net income	–	–	–	–				
Basic	**0.55**	0.54	0.37	0.43	0.49	0.52	0.54	0.52
Diluted	**0.55**	0.54	0.37	0.43	0.49	0.52	0.54	0.52
Distributions declared [2]	**0.525**	0.52	0.51	0.51	0.51	0.505	0.495	0.485

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measures".

(2) Excludes the special distribution issuance of one common share of Utility Group for every 100 trust and exchangeable units held on August 27, 2007, valued at $0.076 per unit.

Identifiable trends in AltaGas' business in the past eight quarters reflect: the organization's internal growth; acquisitions; a favourable business environment including generally increasing power prices in Alberta; asset dispositions; and lower throughput in the FG&P segment.

Significant items that impacted individual quarterly earnings were as follows:

- Results in the FG&P segment are typically lower in the first quarter compared to the fourth quarter;
- In second quarter 2006 a $6.6 million non-cash future income tax benefit was recorded as a result of a reduction in the federal and Alberta corporate income tax rates;
- In fourth quarter 2006 the Trust reported a $0.6 million goodwill impairment and deferred $0.8 million in revenue in the transmission business;
- In second quarter 2007 the Trust recorded a $6.5 million future tax expense as a result of new tax legislation included in Bill C-52 which was substantially enacted by the Government of Canada. This non-cash charge to earnings relates to the temporary differences between the accounting and tax basis of AltaGas' assets and liabilities; and
- In fourth quarter 2007 a $6.1 million non-cash future income tax benefit was recorded as a result of a reduction in the federal corporate income tax rates.

Management's Responsibility for Financial Statements

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. Further, management is satisfied that the financial information contained in this annual report is consistent with that presented in the Consolidated Financial Statements. The internal controls and systems of AltaGas Income Trust (AltaGas or the Trust) are designed to provide reasonable assurance that its assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by the Trust to examine the Consolidated Financial Statements. The Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of directors who are not officers or employees. The Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements in this report.

DAVID W. CORNHILL
CHAIRMAN AND CHIEF EXECUTIVE OFFICER OF ALTAGAS GENERAL PARTNER INC., DELEGATE OF THE TRUSTEE OF ALTAGAS INCOME TRUST

March 3, 2008

DEBORAH S. STEIN
VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER OF ALTAGAS GENERAL PARTNER INC., DELEGATE OF THE TRUSTEE OF ALTAGAS INCOME TRUST

March 3, 2008

Auditors' Report

TO THE UNITHOLDERS OF ALTAGAS INCOME TRUST

We have audited the consolidated balance sheets of AltaGas Income Trust as at December 31, 2007 and 2006 and the consolidated statements of income and accumulated earnings, comprehensive income and accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of AltaGas Income Trust as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

ERNST & YOUNG LLP
CHARTERED ACCOUNTANTS

February 26, 2008
Calgary, Canada

Consolidated Balance Sheets

As at December 31

($ thousands)	2007	2006
ASSETS		
Current assets		
Cash and cash equivalents	**$ 12,451**	$ 13,226
Accounts receivable	**191,879**	224,533
Inventory	**130**	61
Customer deposits	**24,369**	16,304
Risk management (note 12)	**66,811**	–
Other current assets	**9,714**	9,277
	305,354	263,401
Capital assets (notes 4 and 21)	**682,322**	677,941
Energy services arrangements, contracts and relationships (note 5)	**95,716**	103,330
Goodwill (note 6)	**18,260**	18,260
Risk management (note 12)	**33,640**	–
Long-term investments and other assets (note 7)	**64,509**	46,643
	$ 1,199,801	$ 1,109,575
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 177,802**	$ 200,882
Distributions payable to unitholders	**10,167**	9,588
Short-term debt (note 8)	**655**	–
Current portion of long-term debt (note 9)	**1,234**	1,147
Customer deposits	**24,369**	16,304
Deferred revenue	**1,718**	788
Risk management (note 12)	**60,848**	–
Other current liabilities	**9,321**	10,982
	286,114	239,691
Long-term debt (note 9)	**218,845**	264,340
Asset retirement obligations (note 10)	**18,811**	23,350
Future income taxes (note 11)	**58,229**	51,252
Risk management (note 12)	**30,166**	–
Other long-term liabilities	**2,948**	1,526
	615,113	580,159
Unitholders' equity (notes 13 and 14)	**584,688**	529,416
	$ 1,199,801	$ 1,109,575

Commitments (notes 8, 9, 12, 16 and 18)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas General Partner Inc. on behalf of AltaGas Income Trust:

David W. Cornhill

DAVID W. CORNHILL
DIRECTOR

Robert B. Hodgins

ROBERT B. HODGINS
DIRECTOR

Consolidated Statements of Income and Accumulated Earnings

For the years ended December 31

($ thousands except per unit amounts and number of units)	2007	2006
Revenue		
Operating	$ 1,422,242	$ 1,358,189
Unrealized gains on risk management (note 12)	1,115	–
Other	5,037	4,415
	1,428,394	1,362,604
Expenses		
Cost of sales	1,104,399	1,043,691
Operating and administrative	150,297	145,788
Amortization:		
Capital assets	39,477	38,377
Energy services arrangements, contracts and relationships	7,614	7,484
Goodwill impairment (note 6)	–	600
	1,301,787	1,235,940
Operating income	126,607	126,664
Interest expense (notes 8, 9 and 12)		
Short-term debt	491	270
Long-term debt	11,394	13,012
Income before income taxes	114,722	113,382
Income tax expense (recovery) (note 11)	5,928	(1,129)
Net income	108,794	114,511
Accumulated earnings, beginning of year	401,618	287,107
Accumulated earnings, end of year	$ 510,412	$ 401,618
Net income per unit (note 15)		
Basic	$ 1.90	$ 2.06
Diluted	$ 1.89	$ 2.06
Weighted average number of units outstanding (thousands) (note 14)		
Basic	57,382	55,469
Diluted	57,420	55,516

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income

For the year ended December 31

($ thousands)		2007
Net income	**$**	**108,794**
Other comprehensive income, net of tax (note 12)		
Unrealized net gains on available for sale financial assets		**17,902**
Unrealized net gains on derivatives designated as cash flow hedges		**7,051**
Reclassification to net income of net loss on derivatives designated as cash flow hedges pertaining to prior periods		**4,850**
		29,803
Comprehensive income	**$**	**138,597**
Accumulated other comprehensive income, beginning of year		**–**
Adjustment resulting from adoption of new financial instrument accounting standards (note 2)		**(2,634)**
Other comprehensive income, net of tax		**29,803**
Accumulated other comprehensive income, end of year	**$**	**27,169**

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31
($ thousands)

	2007	2006
Cash from operations		
Net income	$ 108,794	$ 114,511
Items not involving cash:		
Amortization	47,091	45,861
Accretion of asset retirement obligations (note 10)	1,474	1,430
Unit-based compensation (note 14)	553	482
Future income tax expense (recovery) (note 11)	5,631	(1,181)
Gain on sale of assets	57	–
Equity income	(2,274)	(3,967)
Distributions from equity investments	1,490	2,950
Goodwill impairment (note 6)	–	600
Unrealized gains on risk management (note 12)	(1,115)	–
Other	1,199	994
Funds from operations	162,900	161,680
Asset retirement obligations settled (note 10)	(346)	(560)
Net change in non-cash working capital (note 17)	20,725	(14,260)
	183,279	146,860
Investing activities		
Increase in customer deposits	(8,065)	(933)
Decrease in note receivable	5,100	–
Acquisition of capital assets	(65,065)	(73,042)
Disposition of capital assets	9,759	509
Disposition of energy services arrangements, contracts and relationships	–	36
Acquisition of long-term investments and other assets	(5,567)	(5,032)
Disposition of long-term investments and other assets	412	–
	(63,426)	(78,462)
Financing activities		
Increase (decrease) in short-term debt	655	(2,710)
Decrease in long-term debt	(45,016)	(829)
Distributions to unitholders	(118,061)	(109,954)
Net proceeds from issuance of units (note 14)	41,794	46,636
	(120,628)	(66,857)
Change in cash and cash equivalents	(775)	1,541
Cash and cash equivalents, beginning of year	13,226	11,685
Cash and cash equivalents, end of year	$ 12,451	$ 13,226

See accompanying notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

(Tabular amounts in thousands of dollars unless otherwise indicated.)

1. Structure of AltaGas Income Trust

AltaGas Income Trust (AltaGas or the Trust) is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to a Declaration of Trust dated March 26, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly held by AltaGas Services Inc. (ASI).

2. Summary of Significant Accounting Policies

These Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

Basis of Presentation

These Consolidated Financial Statements include the accounts of AltaGas Income Trust and all of its wholly owned subsidiaries, and its proportionate interests in various partnerships and joint ventures. Transactions between the Trust and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

Until second quarter 2007 AltaGas accounted for its investment in Taylor NGL Limited Partnership (Taylor) using the equity method. Effective second quarter 2007 AltaGas ceased to exercise significant influence over Taylor and began accounting for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in Other comprehensive income (OCI) (see note 12).

Changes in Accounting Policies

Effective January 1, 2007 the Trust adopted the new CICA Handbook accounting requirements for Section 1506 "Accounting Changes"; Section 1530 "Comprehensive Income"; Section 3251 "Equity"; Section 3855 "Financial Instruments – Recognition and Measurement"; Section 3861 "Financial Instruments – Disclosure and Presentation"; and Section 3865 "Hedges". In accordance with the transitional provisions for these new standards, these policies were adopted prospectively without restatement of prior periods.

ACCOUNTING CHANGES

This section prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. The adoption of this standard did not have a material impact on the Consolidated Financial Statements of the Trust.

FINANCIAL INSTRUMENTS

All financial instruments, including derivatives, are included on the balance sheet initially at fair value. The financial assets are classified as held for trading, held to maturity, loans and receivables, or available for sale. Financial liabilities are classified as held for trading or other financial liabilities. Subsequent measurement is determined by classification.

Held for trading financial assets and liabilities are entered into with the intention of generating a profit and consist of swaps, options and forwards. These financial instruments are initially accounted for at their fair value and changes to fair value are recorded in income. Held to maturity financial assets are accounted for at their amortized cost using the effective interest method. The Trust did not have any held to maturity financial instruments at December 31, 2007. Loans and receivables are accounted for at their amortized cost using the effective interest method. The available for sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications.

Available for sale instruments are initially accounted for at their fair value and changes to fair value are recorded through OCI. Income earned from these investments is included in Revenue.

Other financial liabilities not classified as held for trading are accounted for at their amortized cost, using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded as separate derivatives and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand alone derivative and the total contract is not held for trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the expected purchase, sale or usage requirements exception, are carried on the balance sheet at fair value. The Trust used January 1, 2003 as the transition date for identifying embedded derivatives. The Trust did not identify any embedded derivatives requiring bifurcation.

Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. Effective January 1, 2007 the Trust reclassified $1.1 million of unamortized deferred financing costs from Other current assets and Long-term investments and other assets to Long-term debt as a result of adopting the new standards. The reclassification of transaction costs has no impact on earnings. Effective January 1, 2007 the Trust began amortizing these costs using the effective interest rate method. Previously, these costs were amortized on a straight-line basis over the life of the debt.

HEDGES

The new standard specifies the circumstances under which hedge accounting is permissible, how hedge accounting may be performed and where the impacts should be recorded. The standard introduces three specific types of hedging relationships: fair value hedges, cash flow hedges and hedges of a net investment in self-sustaining foreign operations.

As part of its asset and liability management, the Trust uses derivatives for hedging positions to reduce its exposure to commodity price and foreign exchange risk. The Trust designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Trust performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash flows of the hedged item. All derivatives are initially recorded at fair value and adjusted to fair value at each reporting date.

The Trust uses cash flow hedges to reduce its exposure to fluctuations in interest rates and changes in commodity prices. The effective portion of changes in the value of cash flow hedges is recognized in Other comprehensive income. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income in the same financial category as the underlying transaction. Gains or losses from cash flow hedges that have been included in Accumulated other comprehensive income are included in net income when the underlying transaction has occurred or becomes probable of not occurring. The maximum length of time the Trust is hedging its exposure to variability in future cash flows is 10 years.

COMPREHENSIVE INCOME AND EQUITY

The Trust's financial statements include a Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income which consists of earnings and the effective portion of changes in unrealized gains and losses related to available for sale assets and cash flow hedges. In addition, as required by Section 3251, the Trust now presents separately in its Unitholders' equity note the changes for each of its components of Unitholders' equity. A new component, Accumulated other comprehensive income, and a one-time transition adjustment have been added to the Trust's Unitholders' equity as a result of the implementation of this new standard (see note 12).

NET EFFECT OF ACCOUNTING POLICY CHANGES

The net effect to the Trust's financial statements at January 1, 2007 resulting from the above mentioned changes in accounting policies is as follows:

Balance Sheet Account Affected	Increase (Decrease)
Current assets – risk management	$ 59,866
Other current assets	(451)
Non-current assets	47,942
Long-term investments and other assets	(793)
Current liabilities – risk management	69,618
Long-term debt	(1,082)
Long-term liabilities – risk management	48,359
Future income tax liability	(7,450)
Unitholders' equity – Transition amount on adoption of new accounting standards, net of tax	(247)
Unitholders' equity – Accumulated other comprehensive income, net of tax	(2,634)

The unrealized gains and losses included in the Transition amount and in Accumulated other comprehensive income were recorded net of income tax recoveries of $4.6 million and $2.9 million, respectively.

Business Combinations

All business combinations are accounted for using the purchase method. Under the purchase method assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with banks and investments in money market instruments with original maturities of less than three months.

Inventory

Inventory consists of materials and supplies and is valued at the lower of average cost and replacement cost.

Customer Deposits

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by the Trust. The corresponding liability is classified as customer deposits within current liabilities.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Repairs and maintenance costs are expensed in the period incurred.

The Trust amortizes the cost of capital assets, net of salvage value, on a straight-line basis based on the estimated useful life of the assets.

Field Gathering and Processing (FG&P)	
Gathering and processing assets	15 – 25 years
Other assets	1 – 5 years
Extraction and Transmission (E&T)	
Extraction and transmission assets	15 – 40 years
Power Generation	
Assets under capital lease	10 years

Energy Services	
Energy services assets	unit of production
Other assets	1 – 5 years
Corporate	
Other assets	1 – 5 years

Leases are classified as either capital or operating. Leases which transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases. Assets under capital lease are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise the principal is included as a long-term liability.

Energy Services Arrangements, Contracts, Relationships and Amortization

Energy services arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life:

Sundance B Power Purchase Arrangements (PPAs)	19 years
Natural gas and power marketing contracts	18 – 49 months
Energy services relationships	15 years

AltaGas owns 50 percent of two Sundance B PPAs through its interest in the ASTC Power Partnership (ASTC). ASTC is committed to purchase all of the power from the two 353-megawatt (MW) capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses thereunder are recorded on a proportionate basis. The Sundance B PPAs required a capital outlay to acquire. The Trust is obligated to make payments to the owners of the underlying generating units over the remaining terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the committed power is recorded when delivered.

The Genesee power purchase arrangement had the right to generating capacity at a regulated Alberta generating unit for a three-year period that ended March 31, 2006. This PPA required no capital outlay but included monthly capacity charges, and these amounts were recorded as cost of sales. Revenue from the sale of the committed power was recorded when delivered.

The natural gas and power marketing contracts are the rights and obligations to buy and sell fixed volumes of natural gas and power at contracted prices. Revenue and expenses are recorded when product is delivered.

Energy services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp. (iQ2), PremStar Energy Canada Ltd., ECNG Canada Ltd. and Energistics Group Inc. and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts over the 15-year expected useful life of the relationships.

Goodwill

Goodwill represents that portion of the purchase price on acquisition which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but is tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the implied fair value of goodwill is determined. Any excess of the carrying value of goodwill over its implied fair value is recorded as an impairment charge to income.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost and designated as available for sale. Available for sale assets are initially accounted for at their fair value with changes to fair value recorded through OCI.

Development Costs

The Trust expenses development costs as incurred unless such development costs meet certain criteria related to technical, market and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

The Trust recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to operating and administrative expense in the income statement.

In the E&T segment, certain assets have an indeterminate life and thus a future retirement obligation is not recognized.

Revenue Recognition

In the FG&P segment, revenue is recorded as the services are rendered. In the Power Generation and Energy Services segments, revenue is recognized at the time the product or service is delivered. Within the E&T segment, extraction revenue is recognized at the time the product or service is delivered and transmission revenue is recorded as the services are rendered. Realized gains and losses from risk management activities related to commodity prices are recognized in the related segment revenues when the related sale occurs or when the underlying financial asset or financial liability is removed from the balance sheet. Unrealized gains and losses in respect of fair value changes to the Trust's risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the reporting period in the Corporate segment.

Transaction Costs Related to Financial Instruments

Transaction costs related to the acquisition of held for trading financial assets and liabilities and the Trust's revolving operating credit facility are expensed as incurred. For financial instruments classified as other than held for trading, transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method.

Recognition Date

AltaGas uses the settlement date for transactions. Any difference in value between the trade and settlement date for third-party transactions will be recognized on the balance sheet and in Net income or in OCI as appropriate.

Effective Interest Method

The Trust uses the effective interest method to calculate the amortized cost of a financial asset or liability and to allocate the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate a shorter period, to the net carrying amount of the financial asset or liability.

Unit-Based Compensation Plans

The Trust follows the fair value method of accounting for Trust unit options granted during the year. Unit options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by the Trust on exercise of the option rights is credited to unitholders' capital.

AltaGas has a Mid-Term Incentive Plan in which participants receive phantom units requiring settlement of cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom units is recognized in the period the change occurs.

Pension Plans and Retiree Benefits

The cost of defined benefit pension and other retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost of the benefit is the sum of the individual current service costs and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans is nine to 11 years. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable on income in a particular taxation year that is not paid or payable to the unitholders in such taxation year. Prior to 2007 the Trust allocated all of its Canadian taxable income to the unitholders in accordance with its Trust indenture and met the requirements of the Income Tax Act (Canada) applicable to the Trust. Accordingly, no provision for Canadian income tax expense was made for the Trust.

On June 12, 2007 the Specified Investment Flow-through (SIFT) tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. With the rate of reduction enacted on December 14, 2007 the new tax is to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012 respectively.

Based on the amount of the Trust's temporary differences that are anticipated to reverse after January 1, 2011, the Trust has recorded a future income tax expense and future income tax liability. This non-cash expense relates to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities and has no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Income taxes are calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the substantively enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations and non-routine transactions have been recorded at the exchange amount.

Per Unit Information

Basic net income per unit is calculated on the basis of the weighted average number of trust and exchangeable units outstanding during the year. Diluted net income per unit is calculated as if the proceeds obtained upon exercise of options were used to purchase units at the average market price during the period.

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, as a result of matters that are inherently uncertain, include among others, the fair value of certain assets including long-lived assets and goodwill; recoverability of investments; litigation; environmental and asset retirement obligations; financial instruments; pensions and other post-retirement benefits; unit based compensation; and income taxes. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Future Accounting Changes

SECTION 1535 "CAPITAL DISCLOSURES"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

SECTION 3031 "INVENTORIES"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" provides guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. This new section is effective for the Trust beginning January 1, 2008.

SECTION 3862 "FINANCIAL INSTRUMENTS – DISCLOSURES" AND SECTION 3863 – "FINANCIAL INSTRUMENTS – PRESENTATION"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In 2006 the Accounting Standards Board (AcSB) published a new strategic plan that will significantly affect financial reporting requirements in Canada. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over a five-year transition period with adoption required effective January 1, 2011. While AltaGas has begun assessing the adoption of IFRS for 2011, the financial impact of the transition to IFRS cannot be reasonably estimated at this time.

3. Subsequent Events

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 acquired all of the outstanding limited partnership units of Taylor NGL Limited Partnership (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of natural gas liquids extraction plants, natural gas processing assets and two natural gas liquids pipelines. It also had an interest in a 7-MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders $11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of $245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, $27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. The aggregate purchase price was $598.7 million, including $256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at $198.9 million for all the outstanding units not previously owned by AltaGas, assumed debt of $132.5 million and approximately $ 11 million in transaction costs. The value of the Trust units issued was determined based on the weighted average market price from two days preceding to two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

Total consideration for 100% of Taylor:		
Cost of 8.9% investment in Taylor originally owned by AltaGas		24,672
Purchase price for the remaining 91.1% of Taylor units		
Cash considerations	256,281	
Units	198,862	
Estimated transaction costs	11,000	
Equity portion of Taylor convertible debentures	2,127	468,270
Total consideration		$ 492,942

Purchase price allocation for 100% of Taylor:		
Assets acquired		
Current assets	30,739	
Capital assets	590,030	
Energy service arrangements, contracts and relationships	83,900	
Goodwill	108,191	
Long-term investments and other assets	4,640	817,500
Less Liabilities assumed		
Current liabilities	31,202	
Long-term debt	110,241	
Convertible debentures	22,171	
Asset retirement obligations	14,350	
Future income taxes	144,028	
Future employee obligations	2,542	
Risk management	24	324,558
		$ 492,942

Until the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in OCI. As of January 10, 2008 Taylor will be included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of $256.3 million for the Taylor acquisition. As of January 10, 2008, AltaGas had total debt of approximately $610 million compared to $220.7 million as at December 31, 2007.

Acquisition of Potential Hydroelectric Projects

On February 13, 2008 AltaGas acquired four potential run-of-river hydro projects ranging from 6.5 to 24 MW for $4.5 million. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia. In exchange for the development assets, AltaGas issued 180,433 special warrants for AltaGas trust units valued at $24.94 per special warrant to Plutonic Power Corporation. The special warrants automatically convert to AltaGas units on a one-for-one basis on January 1, 2010.

4. Capital Assets

	2007			2006		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Field Gathering and Processing						
Field gathering and processing assets	**$ 569,944**	**$ (148,297)**	**$ 421,647**	$ 558,411	$ (128,643)	$ 429,768
Other assets	**4,416**	**(2,161)**	**2,255**	2,860	(1,402)	1,458
Extraction and Transmission						
Extraction and transmission assets	**255,810**	**(46,078)**	**209,732**	250,933	(38,023)	212,910
Power Generation						
Capital lease (note 9)	**13,798**	**(4,596)**	**9,202**	13,798	(3,216)	10,582
Power generation assets	**22,013**	**–**	**22,013**	–	–	–
Energy Services						
Energy services assets	**9,693**	**(896)**	**8,797**	30,177	(15,250)	14,927
Other assets	**2,018**	**(156)**	**1,862**	1,990	(385)	1,605
Corporate						
Other assets	**19,230**	**(12,416)**	**6,814**	16,962	(10,271)	6,691
	$ 896,922	**$ (214,600)**	**$ 682,322**	$ 875,131	$ (197,190)	$ 677,941

Interest capitalized on long-term capital construction projects for the year ended December 31, 2007 was $0.8 million (December 31, 2006 – $nil). At December 31, 2007 the Trust had spent approximately $42.6 million (December 31, 2006 – $14.9 million) on capital projects under construction that were not yet subject to amortization.

5. Energy Services Arrangements, Contracts and Relationships

	2007			2006		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Energy services arrangements and contracts	**$ 115,071**	**$ (37,717)**	**$ 77,354**	$ 115,071	$ (31,497)	$ 83,574
Energy services relationships	**20,892**	**(2,530)**	**18,362**	20,892	(1,136)	19,756
	$ 135,963	**$ (40,247)**	**$ 95,716**	$ 135,963	$ (32,633)	$ 103,330

The amortization of the energy services relationships began in 2006 upon expiration of the corresponding short-term marketing contracts.

6. Goodwill

	2007	2006
Balance, beginning of year	**$ 18,260**	$ 18,860
Goodwill impairment	**–**	(600)
Balance, end of year	**$ 18,260**	$ 18,260

In 2006 through its annual goodwill impairment testing AltaGas determined that the fair value of an investment in a business ancillary to the FG&P segment was less than the book value and reduced the carrying value by $0.6 million.

7. Long-Term Investments and Other Assets

	2007	2006
Units of public trusts	**$ –**	$ 375
Equity accounted investments in public entities	**11,813**	40,071
Cost accounted investments in public entities	**44,746**	–
Deferred debt costs, net of amortization	**–**	759
Deferred development costs	**7,242**	4,332
Loans receivable – BMWLP	**–**	700
Warrants	**286**	–
Other	**422**	406
	$ 64,509	$ 46,643

At December 31, 2007 the quoted market value of the holdings of publicly traded entities was approximately $54.2 million (December 31, 2006 – $50.0 million).

The Trust accounts for its interests in AltaGas Utility Group Inc. (Utility Group) as an equity investment.

Until second quarter 2007 AltaGas accounted for its investment in Taylor using the equity method. Effective second quarter 2007 AltaGas ceased to exercise significant influence over Taylor and began accounting for its investment in Taylor using the cost method. As a result, the investment in Taylor is designated as available for sale and is measured at fair value with the changes in fair value recorded in OCI (see note 12).

In 2006 the Trust formed the Bear Mountain Wind Limited Partnership (BMWLP) with Aeolis Wind Power Corporation and the GreenWing Energy Development Limited Partnership (GEDLP) with GreenWing Energy Management Ltd. In 2007 the Trust acquired 100 percent ownership of BMWLP. Through BMWLP and GEDLP, the Trust invested $3.8 million (December 31, 2006 – $4.3 million) in the development of wind power projects. Amortization of these deferred development costs will occur based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

In 2007 AltaGas sold Cedar Energy Partnership in exchange for a $12 million promissory note and received 1 million warrants of the purchaser, each of which will allow AltaGas to subscribe for and purchase one fully paid and non-assessable common share in the capital of the purchaser for a three-year term ending June 1, 2010. The remaining $6.5 million of the promissory note is included in Other current assets.

8. Short-Term Debt

At December 31, 2007 the Trust held a $50.0 million (December 31, 2006 – $50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. At December 31, 2007 the Trust had prime loans of $0.7 million (December 31, 2006 – $nil) and letters of credit of $2.8 million (December 31, 2006 – $3.0 million) outstanding against the facility.

The prime lending rate at December 31, 2007 was 6.0 percent (December 31, 2006 – 6.0 percent).

9. Long-Term Debt

	2007	2006
Operating loans	**$ 10,045**	$ 154,306
Capital lease obligations	**10,034**	11,181
Medium-term notes	**200,000**	100,000
	220,079	265,487
Less current portion	**1,234**	1,147
	$ 218,845	$ 264,340

Letter of Credit Facility

At December 31, 2007 the Trust held a $75.0 million (December 31, 2006 – $75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2007 the Trust had letters of credit of $61.7 million (December 31, 2006 – $63.3 million) outstanding against the extendible revolving-term letter of credit facility.

Operating Loans

At December 31, 2007 the Trust held a $300.0 million (December 31, 2006 – $300.0 million) unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or documentary credits. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw. On September 30, 2007 AltaGas negotiated the extension of the maturity date of this facility to September 30, 2010. On December 14, 2007 AltaGas negotiated minor amendments to the facility in order to facilitate the closing of the Taylor acquisition.

At December 31, 2007 the Trust had drawn $10.0 million (December 31, 2006 – $154.3 million) against the facility. The prime lending rate at December 31, 2007 was 6.0 percent (December 31, 2006 – 6.0 percent). The average rate on the Trust's bankers' acceptances at December 31, 2007 was 5.2 percent (December 31, 2006 – 5.0 percent).

Medium-Term Notes

On April 29, 2005 AltaGas filed a Universal Shelf Prospectus pursuant to which the Trust may issue up to an aggregate of $500.0 million of trust units and debt securities over a 25-month period. AltaGas filed a prospectus supplement on August 23, 2005 establishing AltaGas' medium-term note (MTN) program. On August 30, 2005 $100.0 million of 4.41 percent senior unsecured MTNs were issued. The notes mature on September 1, 2010, with interest payable semi-annually. The proceeds of the issue were used to repay bank debt. On January 19, 2007 AltaGas issued a further $100.0 million of senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012. The net proceeds were used to pay down existing bank indebtness and for general corporate purposes.

Capital Lease Obligation

On September 1, 2004 the Trust entered into a 10-year capital lease for 25 MW of gas-fired power peaking capacity with an option to extend the term for an additional 15 years. The lease has payment commitments over the next five years as follows:

2008	$ 1,878
2009	1,878
2010	1,878
2011	1,878
2012	1,878
Thereafter	3,136
	12,526
Less imputed interest at 6.85%	2,492
Present value of minimum lease payments	10,034
Less current portion	1,234
	$ 8,800

Interest expense on capital leases was $0.7 million in 2007 (December 31, 2006 – $0.8 million).

10. Asset Retirement Obligations

	2007	2006
Balance, beginning of year	**$ 23,350**	$ 16,982
New obligations	**423**	696
Obligations settled	**(346)**	(560)
Obligations disposed	**(4,006)**	–
Revision in estimated cash flow	**(2,084)**	4,802
Accretion expense	**1,474**	1,430
Balance, end of year	**$ 18,811**	$ 23,350

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2007 was $52.4 million (December 31, 2006 – $57.0 million). The asset retirement obligations have been recorded in the financial statements at estimated values discounted at rates between 5.6 percent and 8.3 percent and are expected to be incurred between 2010 and 2040. The majority of the costs are expected to be incurred between 2025 and 2035. No assets have been legally restricted for settlement of the estimated liability.

11. Income Taxes

Taxation of the Trust

Payments received by the Trust in the form of interest, distributions or other income from its subsidiaries are taxable income to the Trust. The Trust is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributes all of its income to unitholders, the Trust is not expected to be liable for income taxes currently.

On June 12, 2007 the Specified Investment Flow-through (SIFT) tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. With the rate of reduction enacted on December 14, 2007 the new tax is to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012 respectively.

Based on the amount of the Trust's temporary differences that are anticipated to reverse after January 1, 2011, the Trust has recorded a future income tax expense of $5.4 million (including $0.1 million in respect of financial instruments) and a future income tax liability in the same amount for the year ended December 31, 2007. This non-cash expense relates to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities and has no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Taxation of the Operating Subsidiaries

Incorporated operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. Operating subsidiaries are generally not expected to pay significant taxes either currently or in the foreseeable future under existing tax legislation.

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before tax as follows:

	2007	2006
Income before taxes – consolidated	**$ 114,722**	$ 113,382
Financial instruments – net	**(1,115)**	–
Income before financial instruments and taxes	**113,607**	113,382
Income from AltaGas Income Trust distributed to unitholders	**(92,544)**	(92,385)
Income before income taxes – operating subsidiaries	**21,063**	20,997
Statutory income tax rate (%)	**32.12**	34.49
Expected taxes at statutory rates	**6,765**	7,242
Add (deduct) the tax effect of:		
SIFT tax	**5,365**	–
Financial instruments	**1,561**	–
Resource allowance	**–**	(1,048)
Rate reductions applied to future income tax liabilities	**(7,256)**	(7,822)
Permanent differences between accounting and tax bases of assets and liabilities	**294**	166
Non-taxable portion of capital gains on disposition of assets and investments	**(1,634)**	–
Other	**833**	333
Income tax provision (recovery)		
Current	**297**	7
Future	**266**	(1,136)
Future SIFT	**5,365**	–
	$ 5,928	$ (1,129)
Effective income tax rate (%)	**5.17**	(1.00)

AltaGas' income taxes are calculated according to government tax laws and regulations which result in different values for certain assets and liabilities for income tax purposes than for financial statement purposes. The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between tax values and book carrying values on the operating subsidiaries' balance sheets at substantively enacted tax rates. GAAP requires these future income tax liabilities to be recognized in the Consolidated Financial Statements. In the case of AltaGas, these future income taxes are not expected to result in cash taxes being paid due to the expectation of continued future intercompany interest deductions at the operating subsidiary level.

As at December 31, future income taxes were composed of the following:

	2007	2006
Capital assets	**$ 31,101**	$ 14,448
Deferred debt charges	**53**	(26)
Unit issue costs	**(635)**	(1,209)
Partnerships	**26,878**	41,522
Deferred compensation	**(2,092)**	(3,408)
Financial instruments	**2,973**	–
Other	**(49)**	(75)
	$ 58,229	$ 51,252

12. Financial Instruments and Financial Risk Management

In the course of normal operations the Trust purchases and sells natural gas, natural gas liquids and power commodities and issues short and long-term debt. The Trust uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Trust does not make use of derivative instruments for speculative purposes.

At December 31, 2007 all derivatives, other than those that meet the expected purchase, sale or usage requirements exception, were carried on the balance sheet at fair value. The fair value of power and natural gas derivatives was calculated using estimated forward prices for the relevant period. The calculation of fair value of the interest rate derivatives used quoted market rates.

At December 31, 2007 the fair value of the Trust's assets and liabilities was as follows:

Summary of Fair Values	Current	Long-term	Total
Financial assets			
Held for trading	$ 54,928	$ 28,272	$ 83,200
Available for sale	–	44,746	44,746
Loans and receivables	208,581	–	208,581
	263,509	73,018	336,527
Cash flow hedges	11,883	5,368	17,251
	$ 275,392	$ 78,386	$ 353,778
Financial liabilities			
Held for trading	$ 56,720	$ 30,079	$ 86,799
Other financial liabilities	168,479	213,608	382,087
	225,199	243,687	468,886
Cash flow hedges	4,128	87	4,215
	$ 229,327	$ 243,774	$ 473,101

Unrealized Income

The impact on net income in 2007 from the adoption of the new financial instruments standards resulted in a $1.1 million unrealized gain.

Other Comprehensive Income

As a part of its hedging program, the Trust uses certain derivative financial instruments to manage risks. An after-tax unrealized loss of $4.8 million was reclassified to net income. Of the $27.2 million gain deferred in Accumulated other comprehensive income (AOCI) at December 31, 2007, a $5.4 million gain is expected to be reclassified to net income in the next 12 months.

The available for sale assets included in the balance sheet caption, Long-term investments and other assets are recognized at fair value, net of tax, in OCI.

Effective January 1, 2007 the Trust began offsetting long-term debt transaction costs against the associated debt and began amortizing these costs using the effective interest rate method. Previously these costs were amortized on a straight-line basis over the life of the debt instrument to which they pertained. There was no material effect on the Trust's financial statements as a result of this change in policy. The effective interest rate for the medium-term notes issued in 2005 and 2007 was 4.54 percent and 5.11 percent, respectively.

Commodity Price Risk Management

NATURAL GAS

The Trust purchases and sells natural gas to its customers. The fixed-price and market-price contracts for both the purchase and sale of natural gas extend to 2012.

At December 31, 2007 the Trust had the following contracts outstanding:

Derivative instruments	Fixed price (per GJ)[1]	Period (months)	Notional volume (GJ) Sales	Notional volume (GJ) Purchases	Fair value
Commodity forward	$2.16 to $10.37	1 – 55	105,375,003	–	$ (17,775)
Commodity forward	$2.16 to $10.37	1 – 55	–	105,375,003	$ 14,754

[1] Certain of the contracts are indexed and as such a price range is not provided.

In 2007 an unrealized gain of $2.0 million was recognized from the Trust's natural gas risk management activities.

NATURAL GAS LIQUIDS

The Trust entered into a series of swaps to lock in a portion of the margin exposed to natural gas liquids (NGL) frac spread.

At December 31, 2007 the Trust had the following contracts outstanding:

Product	Fixed price	Period (months)	Notional volume Sales	Notional volume Purchases	Fair value
Propane	$1.2825 to 1.4725 US/gallon	1 – 12	9,677,178 gallon	–	$ (1,156)
Normal butane	$1.4950 to 1.7000 US/gallon	1 – 12	2,612,064 gallon	–	(685)
WTI	$83.20 to 89.10 US/Bbl	1 – 12	27,489 Bbls	–	(143)
Natural gas	$6.455 to 6.550/GJ	1 – 12	–	1,382,591 GJ	$ 159

In 2007 the Trust recognized an unrealized loss of $0.6 million from the Trust's NGL risk management activities.

POWER

Under the power purchase arrangements AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Trust sells the power to the Alberta Electric System Operator at market prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins to provide predictable earnings. Certain contracts met the expected purchase, sale or usage requirements exception and have not been included in risk management assets or liabilities. At December 31, 2007 the Trust had no intention to terminate any contracts prior to maturity.

At December 31, 2007 the Trust had the following contracts outstanding:

Derivative instruments	Fixed price (per MWh)	Period (months)	Notional volume (MWh) Sales	Notional volume (MWh) Purchases	Fair value
Commodity forward	$79.00 to $80.60	1 – 3	2,160	–	$ (28)
Commodity forward	$63.25 to $68.00	1 – 3	–	2,160	$ 31

The Trust's power risk management activities from financial contracts not included in the hedging program had an unrealized loss of $40,248.

At December 31, 2007 the Trust had the following commodity swaps and collars outstanding:

Derivative instruments	Fixed price (per MWh)	Period (months)	Notional volume (MWh) Sales	Purchases	Fair value
Swaps and collars	$65.00 to $88.00	1 – 24	1,626,624	–	$ 10,932
Swaps and collars	$56.50 to $56.50	1 – 120	–	263,016	$ 3,339

At December 31, 2007 the Trust had the following heat rate hedges outstanding:

Derivative instruments	Fixed price (per GJ or MWh)	Period (months)	Notional volume (GJ or MWh) Sales	Purchases	Fair value
Natural gas (per GJ)	$6.08 to $6.17	1	–	79,050	$ 17,968
Power (per MWh)	$89.00 to $138.00	1	6,510	–	$ 170,019

In 2007 an unrealized gain of $0.2 million was recognized from the Trust's heat rate hedging activities.

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, the Trust enters into foreign exchange forward contracts. For 2007 the Trust's foreign exchange risk management activities had an unrealized loss of $0.7 million.

Interest Rate Risk Management

To hedge against the effect of future interest rate movements, the Trust enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities. In January 2007 the Trust unwound certain of these interest rate swaps as a result of the issue of $100 million of medium-term notes and recorded a gain of $0.4 million. In the third quarter the Trust terminated the hedge relationship on certain swap agreements resulting in an immaterial unrealized gain. The remaining interest rate swaps have an average remaining term of 2 to 15 months and a weighted average interest rate of 3.56 percent. The Trust's interest rate risk management activities resulted in an unrealized gain of $0.2 million and fair market value position of $0.2 million at December 31, 2007.

Credit Risk on Financial Instruments

Credit risk results from the possibility that a counterparty to a derivative in which the Trust has an unrealized gain fails to perform according to the terms of the contract.

Credit exposure is minimized by entering into transactions with creditworthy counterparties in accordance with established credit policies and practices. At December 31, 2007 AltaGas did not have a significant concentration of credit risk with any single counterparty to financial instruments.

13. Unitholders' Equity

	2007	2006
Unitholders' capital (note 14)	**$ 505,544**	$ 463,750
Contributed surplus	**3,875**	3,322
Accumulated earnings	**510,412**	401,618
Accumulated dividends	**(41,114)**	(41,114)
Accumulated unitholders' distributions declared [1]	**(391,103)**	(272,464)
Distributions of common shares of Utility Group	**(29,848)**	(25,696)
Transition adjustment resulting from adopting new financial instruments accounting standards	**(247)**	–
Accumulated other comprehensive income	**27,169**	–
	$ 584,688	$ 529,416

[1] Accumulated unitholders' distributions paid by the Trust as at December 31, 2007 were $380.9 million (as at December 31, 2006 – $262.9 million).

In 2007 the holders of trust units of the Trust and holders of exchangeable partnership units of AltaGas Holding Limited Partnership No. 1 received one common share of Utility Group for every 100 trust or exchangeable units held on August 27, 2007. As part of the distribution plan, any unitholder allocated fewer than 50 common shares of Utility Group received cash. The number of common shares of Utility Group distributed to unitholders was 577,416, which reduced unitholders equity by $4.2 million. This distribution resulted in a 27 percent reduction of the Trust's interest in Utility Group to 19.6 percent.

14. Unitholders' Capital

The Trust is authorized to issue:

- An unlimited number of trust units redeemable for cash at the option of the holder;
- An unlimited number of AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2014 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #1 units outstanding fall below 750,000. After May 1, 2014 the exchange is at the option of either the Trust or the unitholder; and
- An unlimited number of AltaGas Holding Limited Partnership No. 2 (AltaGas LP #2) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2009 the exchange is at the option of the unitholder at anytime, and at the option of the Trust should the number of AltaGas LP #2 units outstanding fall below 1,000,000. After May 1, 2009 the exchange is at the option of either the Trust or the unitholder.

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2005	52,505,514	$ 404,854
Units issued for cash on exercise of options	9,150	127
Units issued under DRIP [1]	1,745,630	46,509
Units issued for exchangeable units	53,258	305
December 31, 2006	54,313,552	451,795
Exchangeable Units Issued and Outstanding:		
December 31, 2005 issued by AltaGas LP #1	2,142,072	12,260
AltaGas LP #1 units redeemed for trust units	(53,258)	(305)
December 31, 2006	2,088,814	11,955
Issued and outstanding at December 31, 2006	56,402,366	$ 463,750

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2006	**54,313,552**	**$ 451,795**
Units issued for cash on exercise of options	**3,400**	**68**
Units issued under DRIP [1]	**1,692,128**	**41,726**
Units issued for exchangeable units	**48,358**	**277**
December 31, 2007	**56,057,438**	**493,866**
Exchangeable Units Issued and Outstanding:		
December 31, 2006 issued by AltaGas LP #1	**2,088,814**	**11,955**
AltaGas LP #1 units redeemed for trust units	**(48,358)**	**(277)**
December 31, 2007	**2,040,456**	**11,678**
Issued and outstanding at December 31, 2007	**58,097,894**	**$ 505,544**

[1] Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan.

The Trust has an employee unit option plan under which both employees and directors are eligible to receive grants. At December 31, 2007, 10 percent of units outstanding were reserved for issuance under the plan. To December 31, 2007 options granted under the plan generally had a term of 10 years to expiry and vested no longer than over a four-year period.

At December 31, 2007 outstanding options were exercisable at various dates to the year 2017 (December 31, 2006 – 2016). Options outstanding under the plan have a weighted average exercise price of $26.36 (December 31, 2006 – $27.23) and a weighted average remaining term of 8.76 years (December 31, 2006 – 9.23 years). As at December 31, 2007 the unexpensed fair value of unit option compensation cost associated with future periods was $0.7 million (December 31, 2006 – $0.9 million).

The following table summarizes information about the Trust's unit options:

	Options outstanding			
	2007		2006	
	Number of options	Exercise price (1)	Number of options	Exercise price (1)
Unit options outstanding, beginning of year	**923,550**	**$ 27.23**	359,200	$ 24.53
Granted	**548,500**	**25.31**	636,500	28.60
Exercised	**(3,400)**	**20.06**	(9,150)	13.93
Cancelled	**(158,250)**	**27.94**	(63,000)	27.53
Unit options outstanding, end of year	**1,310,400**	**$ 26.36**	**923,550**	**$ 27.23**
Unit options exercisable, end of year	**331,425**	**$ 25.50**	**106,513**	**$ 20.48**

(1) Weighted average.

A summary of the plan as at December 31, 2007:

	Options outstanding			Options exercisable	
	Number outstanding (1)	Exercise price (2)	Remaining contractual life (3)	Number exercisable (1)	Exercise price (2)
$5.00 – $7.00	9,000	$ 6.10	2.45	9,000	$ 6.10
$7.01 – $15.50	28,500	10.26	5.15	28,500	10.26
$15.51 – $25.08	416,400	24.77	9.23	54,300	24.16
$25.09 – $29.50	856,500	27.86	8.72	239,625	28.35
	1,310,400	**$ 26.36**	**8.76**	**331,425**	**$ 25.50**

(1) As at December 31, 2007.

(2) Weighted average.

(3) Weighted average number of years.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted-average assumptions for grants as follows:

	2007	2006
Risk-free interest rate (%)	**3.29**	4.36
Expected lives (years)	**10**	10
Expected volatility (%)	**21.71**	20.89
Annual distribution per unit ($)	**2.04**	1.981

Units Outstanding [1]	2007	2006
Number of units – basic [2]	**57,382,209**	55,468,969
Dilutive stock options	**37,632**	47,216
Number of units – diluted [2]	**57,419,841**	55,516,185

[1] Includes exchangeable units.

[2] Weighted average.

In 2004 AltaGas implemented a unit-based compensation plan which awards phantom units to certain employees. The phantom units are valued on distributions declared and the trading price of the Trust's units. The units vest on a graded vesting schedule. The compensation expense recorded in 2007 in respect of this plan was $5.1 million (December 31, 2006 – $6.7 million). As at December 31, 2007 the unexpensed fair value of unit-based compensation costs associated with future periods was $14.2 million (December 31, 2006 – $9.9 million).

15. Income Per Unit

The following table summarizes the computation of net income per unit:

	2007	2006
Numerator:		
Numerator for basic income per unit	**$ 108,794**	$ 114,511
Numerator for basic and diluted income per unit	**$ 108,794**	$ 114,511
Denominator:		
Weighted-average number of units	**57,382**	55,469
Dilutive unit options	**38**	47
Denominator for diluted income per unit	**57,420**	55,516
Basic income per unit	**$ 1.90**	$ 2.06
Diluted income per unit	**$ 1.89**	$ 2.06

16. Commitments

Future minimum lease payments under operating leases for office space, office equipment, and automotive equipment are estimated as follows:

2008	$ 3,887
2009	3,606
2010	3,181
2011	2,798
2012	2,499
	$ 15,971

Under the terms of a 1997 long-term gas supply contract, the Trust is committed to supply natural gas for prices ranging from $2.34/Mcf in 2007 to $2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. In 1999, one of those producers defaulted on its obligation under its gas supply contract, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed-price contract with a third-party supplier to fix the price of the gas supply related to the commitment until its expiry in 2009.

In 1999 the Trust acquired a right to purchase natural gas from specific reserves for $0.05/Mcf for the life of the reserves. The production from these reserves was 1,039 Mcf/d in 2007 (2006 – 1,321 Mcf/d).

In 2007 AltaGas entered into a supply and installation agreement with Enercon GmbH to supply and install wind turbines for the Bear Mountain Wind project. The Trust has an obligation to pay approximately $144 million before the supply and installation is complete. The Trust has also entered into other supply agreements to pay approximately $6 million for equipment and construction costs associated with the Bear Mountain Wind project.

17. Net Change in Non-Cash Working Capital

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

	2007	2006
Accounts receivable	**$ 32,654**	$ (3,849)
Inventory	**(69)**	34
Other current assets	**6,065**	(4,856)
Accounts payable and accrued liabilities	**(23,080)**	(14,719)
Customer deposits	**8,065**	933
Deferred revenue	**930**	788
Other current liabilities	**(1,661)**	209
	22,904	(21,460)
Less decrease (increase) in capital costs payable	**(2,179)**	7,200
Net change in non-cash working capital related to operations	**$ 20,725**	$ (14,260)

The following cash payments have been included in the determination of earnings:

	2007	2006
Interest paid	**$ 12,078**	$ 13,521
Income taxes paid	**$ 181**	$ 62

18. Pension Plans and Retiree Benefits

Defined Contribution Plan

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all regular employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was $1.4 million for the year ended December 31, 2007 (December 31, 2006 – $1.3 million).

Defined Benefit Plans

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine Trust employees for pre-AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Effective January 1, 2005 the plan was amended in respect of certain employees who transferred employment from AltaGas Utilities Inc., a then wholly owned subsidiary to the Trust during most of 2005. Assets and liabilities were transferred to Parts III and IV of the Salaried Employees' Pension Plan for three such employees during 2006.

Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2007 and 2006 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2005 based upon a report dated March 29, 2006. As at December 31, 2007 the accrued benefit obligation of the Trust for this plan was $1.9 million (December 31, 2006 – $1.9 million). At December 31, 2007, the plan had an accrued benefit liability recognized in the financial statements of $0.3 million (December 31, 2006 – $0.3 million).

For the year ended December 31, 2007, the net pension cost was a recovery of $15,000 (December 31, 2006 – recovery of $11,000).

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005 the Trust instituted a non-registered, defined benefit retirement plan which provides defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. As at December 31, 2007 the accrued benefit obligation of the Trust for this plan was $3.0 million (December 31, 2006 – $2.1 million). At December 31, 2007 the plan had an accrued benefit liability recognized in the financial statements of $1.9 million (December 31, 2006 – $1.0 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a Retirement Compensation Arrangement Trust account.

For the year ended December 31, 2007 the net pension expense was $1.0 million (December 31, 2006 – $0.8 million).

The following table summarizes the details of the defined benefit plans:

	2007	2006
Accrued benefit obligation		
Balance, beginning of year	**$ 4,079**	$ 2,987
Net transfer in	**–**	165
Actuarial loss (gain)	**(73)**	96
Current service cost	**738**	657
Interest cost	**240**	174
Benefits paid	**(83)**	–
Balance, end of year	**4,901**	4,079
Plan assets		
Fair value, beginning of year	**1,729**	1,409
Net transfers in	**–**	164
Actual return (loss) on plan assets	**(71)**	144
Employer contributions	**11**	12
Benefits paid	**(83)**	–
Fair value, end of year	**1,586**	1,729
Funded deficit	**(3,315)**	(2,350)
Unamortized past service costs	**778**	855
Unamortized net actuarial loss	**330**	227
Accrued benefit asset (liability) recognized in the financial statements	**$ (2,207)**	$ (1,268)

	2007	2006
Significant actuarial assumptions used as at December 31		
Discount rate (%)	**5.50**	5.25 – 5.50
Expected long-term rate of return on plan assets (%)	**6.00 – 6.75**	6.00 – 6.75
Rate of compensation increase (%)	**3.50 – 4.00**	3.50 – 4.00
Average remaining service life of active employees (years)	**9 – 11**	9 – 12
Net benefit plan expense for the year		
Current service cost and expenses	**$ 739**	$ 657
Interest cost	**240**	174
Actual loss (return) on plan assets	**71**	(144)
Actuarial loss (gain)	**(73)**	96
Costs arising in the year	**977**	783
Differences between costs arising in the year and costs recognized in the year in respect of:		
Return on plan assets	**(188)**	49
Actuarial gains (loss)	**84**	(87)
Past service costs	**77**	77
Net periodic benefit plan costs recognized	**$ 950**	$ 822

19. Related Party Transactions

In the normal course of business, the Trust and its affiliates transact with related parties. These transactions are recorded at their exchange amounts and are as follows:

	2007	2006
Fees for administration, management and other services paid by:		
Utility Group to the Trust	**$ 29**	$ 30
The Trust to Utility Group	**$ 445**	$ 1,001
Natural gas sales by the Trust to Utility Group subsidiaries	**$ 83,370**	$ 84,046
Fees for operating services paid by Utility Group subsidiaries	**$ 341**	$ 469
Transportation services provided by Utility Group subsidiaries	**$ 477**	$ 560
Office space and furniture rental payments made by the Trust to a corporation owned by an employee	**$ 85**	$ 83

The resulting amounts due from and to related parties are non-interest bearing and are related to transactions in the normal course of business.

Included in accounts receivable at December 31, 2007 was $13.5 million (December 31, 2006 – $13.8 million) due to the Trust from related parties. Included in accounts payable at December 31, 2007 is $50,000 (December 31, 2006 – $0.7 million) due from the Trust to related parties.

During 2007 AltaGas sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for $9.0 million to execute the divestiture of non-core production assets.

20. Joint Ventures

The Trust's proportionate interest in its joint venture arrangements is summarized as follows:

	2007	2006
Proportionate share of operating income		
Revenues	**$ 201,124**	$ 234,243
Expenses	**131,220**	156,649
	$ 69,904	$ 77,594
Proportionate share of net assets		
Current assets	**$ 33,135**	$ 44,386
Capital assets	**91,238**	93,917
Energy services arrangements, contracts and relationships	**75,483**	81,292
Long-term investments and other assets	**3,643**	4,637
Current liabilities	**(32,780)**	(43,129)
	$ 170,719	$ 181,103
Proportionate share of cash flows		
Operating activities	**$ 79,959**	$ 83,367
Investing activities	**(571)**	(57,826)
Financing activities	**(79,388)**	(25,541)
	$ –	$ –

21. Disposition on Sale of Capital Assets

During 2007 AltaGas sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for cash, effective July 31, 2007 at the exchange amount of $9.0 million. The gain on the sale was negligible. In 2007 AltaGas recorded a one-time gain of $1.5 million from the sale of oil and natural gas production assets for non-monetary consideration totaling $11.9 million including a promissory note of $11.6 million. The disposition also resulted in the reduction in the asset retirement obligation by $3.7 million.

22. Segmented Information

AltaGas is an integrated energy Trust with a portfolio of assets and services used to move energy from the source to the end-user. Transactions among the reporting segments are recorded at fair value. The following describes the Trust's five reporting segments:

Field Gathering and Processing – natural gas gathering lines and processing facilities;

Extraction and Transmission – ethane and natural gas liquids extraction plants and natural gas and condensate transmission pipelines;

Power Generation – coal-fired and gas-fired power output under power purchase arrangements and other agreements;

Energy Services – energy management and gas services for natural gas and electricity; and

Corporate – the costs of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management assets and liabilities.

The following tables show the breakdown by segment:

For the year ended December 31, 2007	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Intersegment elimination	Total
Revenue	$ 135,105	$ 142,938	$ 182,535	$ 1,022,506	$ 5,037	$ (60,842)	$ 1,427,279
Unrealized gains (losses) on risk management	–	–	–	–	1,115	–	1,115
Cost of sales	(7,655)	(75,495)	(78,373)	(1,001,599)	–	58,723	(1,104,399)
Operating and administrative	(83,344)	(20,300)	(2,035)	(15,576)	(31,161)	2,119	(150,297)
Amortization	(25,901)	(8,055)	(7,488)	(3,307)	(2,340)	–	(47,091)
Operating income (loss)	$ 18,205	$ 39,088	$ 94,639	$ 2,024	$ (27,349)	–	$ 126,607
Operating income (loss) before unrealized gains (losses) on risk management	$ 18,205	$ 39,088	$ 94,639	$ 2,024	$ (28,464)	–	$ 125,492
Net additions (reductions) to:							
Capital assets	$ 13,213	$ 4,672	$ 22,013	$ (20,457)	$ 2,349	–	$ 21,790
Long-term investments and other assets	–	–	$ (530)	–	$ 18,396	–	$ 17,866
Goodwill	$ 215	$ 18,045	–	–	–	–	$ 18,260
Segment assets	$ 507,876	$ 241,198	$ 151,401	$ 124,702	$ 174,624	–	$ 1,199,801

For the year ended December 31, 2006	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Intersegment elimination	Total
Revenue	$ 139,016	$ 149,143	$ 199,344	$ 948,939	$ 4,415	$ (78,253)	$ 1,362,604
Cost of sales	(9,381)	(85,888)	(99,761)	(924,249)	–	75,588	(1,043,691)
Operating and administrative	(80,068)	(20,305)	(1,332)	(17,060)	(29,688)	2,665	(145,788)
Amortization	(23,579)	(7,733)	(7,382)	(4,848)	(2,319)	–	(45,861)
Goodwill impairment	(600)	–	–	–	–	–	(600)
Operating income (loss)	$ 25,388	$ 35,217	$ 90,869	$ 2,782	$ (27,592)	–	$ 126,664
Operating income (loss) before unrealized gains (losses) on risk management	$ 25,388	$ 35,217	$ 90,869	$ 2,782	$ (27,592)	–	$ 126,664
Net additions (reductions) to:							
Capital assets	$ 62,295	$ 4,319	$ (28)	$ 1,652	$ 2,270	–	$ 70,508
Energy service arrangements, contracts and relationships	–	$ –	–	$ (36)	–	–	$ (36)
Long-term investments and other assets	–	$ –	$ 4,332	–	$ 1,390	–	$ 5,722
Goodwill	$ 215	$ 18,045	–	–	–	–	$ 18,260
Segment assets	$ 528,636	$ 258,480	$ 140,427	$ 131,907	$ 50,125	–	$ 1,109,575

23. Comparative Figures

Certain comparative figures have been reclassified to conform to the current financial statement presentation.

10-Year Review of Financial and Operating Information

($ millions unless otherwise indicated)	2007	2006	2005	2004
Financial Highlights				
Income Statement				
Revenue	**1,428.4**	1,362.6	1,502.3	864.6
Net revenue [1] [2]				
Gathering, Processing and Energy Services	**–**	–	–	–
Gathering and Processing	**–**	–	–	160.1
Field Gathering and Processing	**127.4**	129.7	120.1	–
Extraction and Transmission	**67.4**	63.2	58.0	–
Power Generation	**104.2**	99.6	57.8	–
Energy Services	**20.9**	24.7	23.5	59.9
Natural Gas Distribution [3]	**–**	–	29.0	30.7
Corporate	**6.2**	4.4	10.9	–
Intersegment elimination	**(2.1)**	(2.7)	(2.4)	(0.3)
	324.0	318.9	296.9	250.4
EBITDA [1]	**173.7**	173.1	155.5	133.4
Net income	**108.8**	114.5	90.3	65.8
Net income per basic unit	**$ 1.90**	$ 2.06	$ 1.67	$ 1.33
EBITDA per basic unit [1]	**$ 3.03**	$ 3.12	$ 2.88	$ 2.70
Cash Flow				
Funds from operations [1]	**162.9**	161.7	129.0	108.6
Funds from operations per basic unit [1]	**$ 2.84**	$ 2.91	$ 2.39	$ 2.20
Distributions/dividends per unit declared [4]	**$ 2.065**	$ 1.995	$ 1.85	$ 1.31
Balance Sheet				
Capital assets	**682.3**	677.9	645.4	746.7
Energy services arrangements, contracts and relationships	**95.7**	103.3	110.9	113.1
Total assets	**1,199.8**	1,109.6	1,068.3	1,108.6
Short-term debt	**0.7**	–	2.7	7.0
Long-term debt	**220.0**	265.5	266.3	352.5
Unitholders' equity	**584.7**	529.4	478.6	483.5
Unit Data (millions)				
Units outstanding at year-end	**58.1**	56.4	54.6	53.2
Weighted average units outstanding for the year (basic)	**57.4**	55.5	54.0	49.4
Ratios (%)				
Return on average equity	**19.8**	22.7	18.4	15.7
Return on average invested capital	**16.2**	16.3	13.0	11.6
Debt as a percent of total capitalization	**27.4**	33.4	36.0	42.6
Operating Results				
Field Gathering and Processing				
Capacity (gross Mmcf/d) [5]	**1,023**	1,021	962	913
Throughput (gross Mmcf/d) [6]	**511**	549	573	558
Throughput (gross annual Mmcf/d)	**527**	555	563	560
Capacity utilization (%) [6]	**52**	54	60	61
Extraction and Transmission				
Extraction inlet capacity (Mmcf/d) [5]	**554**	554	539	539
Production (Bbls/d) [7]	**20,108**	19,696	19,357	13,436
Transmission volumes (Mmcf/d) [8] [9]	**407**	400	432	432
Frac spread ($/Bbl) [7] [10]	**21.38**	18.47	9.31	10.51
Power Generation				
Volume of power sold (GWh) [7]	**2,661**	2,878	3,466	3,481
Price received on the sale of power ($/MWh) [7]	**68.59**	69.26	54.59	48.77
Alberta Power Pool price ($/MWh) [7]	**66.84**	80.48	70.19	54.54
Energy Services				
Energy management service contracts [5]	**1,466**	1,394	1,243	427
Average gas volumes marketed (GJ/d) [11]	**388,217**	327,057	312,272	174,337
Natural Gas Distribution [3] [12]				
Volume of natural gas distributed				
Sales (Bcf)	**–**	–	10	14
Transportation (Bcf)	**–**	–	9	11
Number of customers [5]	**–**	–	61,447	60,430
Degree day variance (%) [13]	**–**	–	(1.4)	2.6

2003	2002	2001	2000	1999	1998
710.6	492.7	489.8	506.7	257.8	122.1
–	–	111.0	88.5	61.8	36.3
137.8	99.6	–	–	–	–
–	–	–	–	–	–
–	–	–	–	–	–
–	–	–	–	–	–
49.3	44.2	–	–	–	–
30.6	28.9	26.9	28.1	27.2	12.9
–	–	–	–	–	–
(0.4)	(2.8)	(2.9)	(0.3)	(3.1)	(1.4)
217.3	169.9	135.0	116.3	85.9	47.8
121.9	94.8	69.9	57.0	42.8	24.1
38.3	29.4	19.2	17.6	11.3	7.2
$ 0.84	$ 0.70	$ 0.50	$ 0.46	$ 0.43	$ 0.39
$ 2.68	$ 2.24	$ 1.83	$ 1.50	$ 1.62	$ 1.31
90.2	70.8	50.2	40.5	28.6	16.1
$ 1.98	$ 1.67	$ 1.31	$ 1.06	$ 1.08	$ 0.88
$ 0.38	$ 0.28	$ 0.18	–	–	–
677.9	663.4	521.0	453.0	376.9	280.5
101.0	107.0	112.2	–	–	–
919.3	904.9	721.1	581.1	436.5	327.1
4.5	50.6	100.0	–	–	–
392.4	368.9	283.9	216.9	151.9	160.3
363.3	338.6	261.9	250.6	230.8	129.1
45.7	45.2	38.5	38.2	37.8	18.9
45.5	42.3	38.2	38.1	26.4	18.4
10.9	9.8	7.3	7.0	6.6	9.0
11.1	9.3	8.7	8.6	8.4	9.4
52.2	55.3	58.5	45.6	39.0	54.7
861	842	768	712	658	494
523	532	498	434	371	276
520	492	489	418	330	208
61	63	65	61	56	56
349	349	219	211	199	155
7,575	3,399	2,618	3,369	2,198	956
403	106	47	36	26	16
6.23	6.35	–	–	–	–
3,266	2,669	–	–	–	–
47.56	41.27	–	–	–	–
62.98	43.85	–	–	–	–
–	–	–	–	–	–
–	–	–	–	–	–
14	14	13	14	13	6
10	8	8	7	6	3
59,543	58,499	57,542	56,692	55,636	55,147
6.9	7.8	(3.4)	6.5	(1.1)	–

Comparative figures for 2004 and prior years have not been restated to conform to the current financial presentation.

(1) Non-GAAP financial measure. See discussion on page 28.

(2) Resegmentations occurred in 2005 and 2002. Prior years were not restated.

(3) AltaGas purchased 100 percent of the outstanding common shares of AltaGas Utilities Inc. on June 30, 1998. On November 17, 2005 AltaGas spun-out its Natural Gas Distribution segment to AltaGas Utility Group Inc. (Utility Group), of which it holds a 19.6 percent interest.

(4) Distributions declared do not include $0.54 per unit declared in November 2005 in the form of shares of Utility Group as a result of the spin-out of the Natural Gas Distribution business, or $0.076 per unit in August 2007, also in the form of shares of Utility Group.

(5) As at December 31.

(6) Fourth quarter average.

(7) Annual average.

(8) Average for fourth quarter except for 1998, which only included December.

(9) Volumes do not include condensate pipeline volumes.

(10) AltaGas reports an indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

(11) Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

(12) Excludes Inuvik Gas Ltd. and Heritage Gas Limited.

(13) Variance from 20-year average – positive variances are favourable.

Unitholder Information

2007 Distributions per Unit

Declaration Date	Record Date	Payment Date	Total Cash Distribution
January 12, 2007	January 25, 2007	February 15, 2007	$0.170
February 14, 2007	February 26, 2007	March 15, 2007	$0.170
February 28, 2007	March 26, 2007	April 16, 2007	$0.170
April 11, 2007	April 25, 2007	May 15, 2007	$0.170
May 9, 2007	May 25, 2007	June 15, 2007	$0.170
June 13, 2007	June 25, 2007	July 16, 2007	$0.170
July 12, 2007	July 25, 2007	August 15, 2007	$0.170
August 8, 2007	August 27, 2007	September 17, 2007	$0.175*
September 12, 2007	September 25, 2007	October 15, 2007	$0.175
October 12, 2007	October 25, 2007	November 15, 2007	$0.175
November 7, 2007	November 26, 2007	December 17, 2007	$0.175
December 12, 2007	December 27, 2007	January 15, 2008	$0.175
Total 2007 Cash Distribution Declared			$2.065

* In addition, a special distribution of one AltaGas Utlity Group Inc. (Utility Group) common share was issued for every 100 Trust units and exchangeable units held on August 27, 2007. Any Trust unitholder allocated fewer than 50 common shares of Utility Group received cash. The cash value of the distribution was determined to be $0.076 per unit.

Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan (DRIP or the plan)

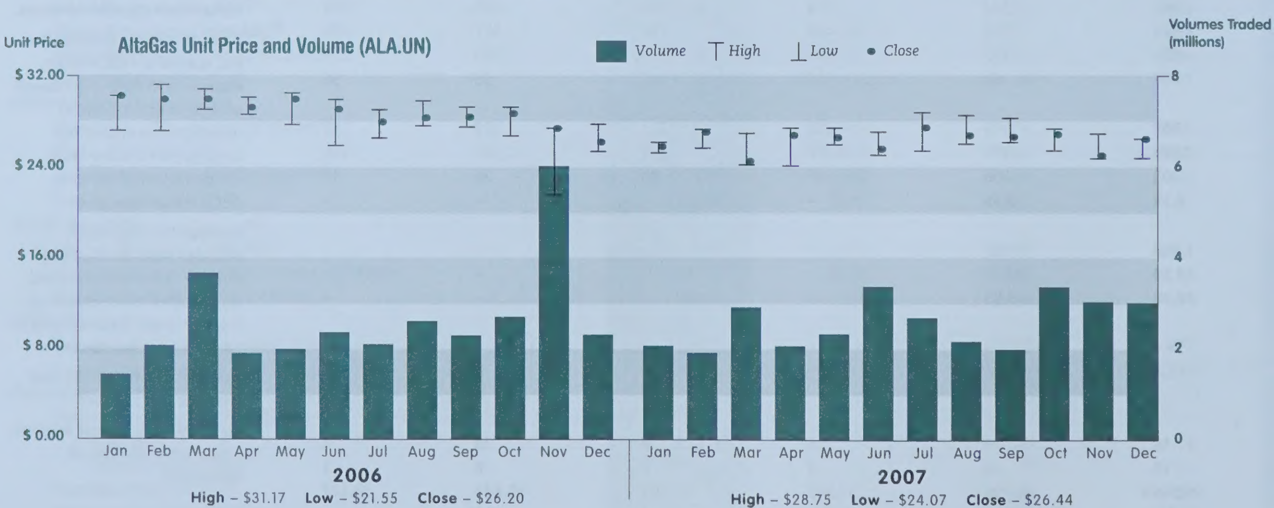
AltaGas Income Trust offers a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan for eligible holders of Trust units and limited partnership units that are exchangeable into Trust units (Exchangeable Units).

The plan provides unitholders with a convenient and economical way to maximize their investment in AltaGas by providing the opportunity to:

- Reinvest cash distributions into Trust units at a 5 percent discount to the average market price, under the distribution reinvestment component of the plan; or
- Receive a 2 percent premium cash distribution, under the premium distribution component of the plan. AltaGas has suspended the Premium component of the plan. While the Premium component of the plan is suspended, participants will continue to receive regular cash distributions.
- Eligible unitholders may also make optional trust unit purchases at the weighted average market price.

Registered unitholders who are eligible and wish to participate in the plan must enroll directly with Computershare Trust Company of Canada, while beneficial unitholders should contact their broker, investment dealer, financial institution or other nominee that holds their units, in order to enroll.

Complete details on the DRIP are available on the AltaGas website at www.altagas.ca.



Corporate Information

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CHAIRMAN AND CHIEF EXECUTIVE OFFICER

Richard M. Alexander
PRESIDENT AND CHIEF OPERATING OFFICER

Massimiliano Fantuz
EXECUTIVE VICE PRESIDENT

Deborah S. Stein
VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER

David R. Wright
EXECUTIVE VICE PRESIDENT STRATEGY AND CORPORATE DEVELOPMENT

Gregory A. Aarssen
VICE PRESIDENT CORPORATE AFFAIRS

Nancy A. Anderson
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Jeremy R. Baines
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Investors are encouraged to contact Computershare for information concerning their security holdings.

STOCK EXCHANGE LISTING

Toronto Stock Exchange: ALA.UN

ANNUAL MEETING

The annual meeting will be held at 3:00 p.m. MDT on Thursday, April 24, 2008 at The Metropolitan Centre, Strand/Tivoli Room, 333 – 4th Avenue S.W., Calgary, Alberta.

INVESTOR RELATIONS

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DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
bps	basis points
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour

PHOTOGRAPHS
FRONT COVER, LEFT TO RIGHT: EDMONTON EXTRACTION PLANT; ENERCON WIND TURBINE.
PAGE 8, CLOCKWISE: EDMONTON EXTRACTION PLANT; EDMONTON EXTRACTION PLANT; POUCE COUPE GAS PROCESSING PLANT; POUCE COUPE GAS PROCESSING PLANT.
PAGE 10, CLOCKWISE: ENERCON WIND TURBINE; BOSTON BAR RUN-OF-RIVER HYDROELECTRIC FACILITY; COALDALE GAS-FIRED PEAKING PLANT; TRANSALTA CORPORATION SUNDANCE POWER PLANT.

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